PB85-233112

Equipment Leaks of VOC (Volatile Organic Compound) in Natural Gas Production Industry Background Information for Promulgated Standards. Final Report

(U.S.) Environmental Protection Agency
Research Triangle Park, NC

May 85

U.S. Department of Commerce
National Technical Information Service
NTIS

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-450/3-82-024b
May 1985

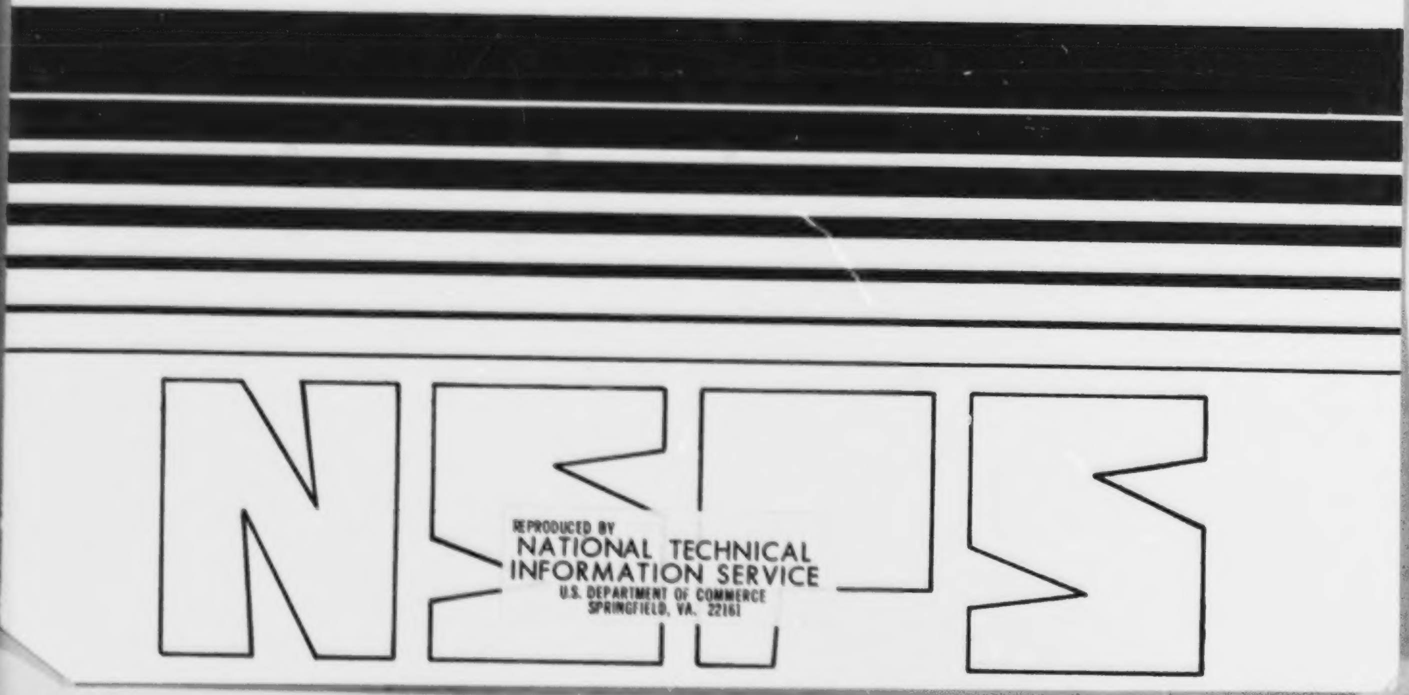
PB85-233112

Air

EPA

Equipment Leaks of VOC in Natural Gas Production Industry — Background Information for Promulgated Standards

EIS



REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO.
EPA-450/3-82-024b

2.

3. RECIPIENT'S ACCESSION NO.
PB85 233112/AS

4. TITLE AND SUBTITLE
Equipment Leaks of VOC in Natural Gas Production Industry - Background Information for Promulgated Standards

5. REPORT DATE
May 1985

6. PERFORMING ORGANIZATION CODE

7. AUTHOR(S)

8. PERFORMING ORGANIZATION REPORT NO.

9. PERFORMING ORGANIZATION NAME AND ADDRESS
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

10. PROGRAM ELEMENT NO.

11. CONTRACT/GRANT NO.
68-02-3060

12. SPONSORING AGENCY NAME AND ADDRESS
Director for Air Quality Planning and Standards
Office of Air, Noise, and Radiation
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

13. TYPE OF REPORT AND PERIOD COVERED

14. SPONSORING AGENCY CODE
EPA/200/04

15. SUPPLEMENTARY NOTES This document presents the background information used by the Environmental Protection Agency in developing the promulgated new source performance standards for equipment leaks of VOC in the natural gas production industry.

16. ABSTRACT

Standards of performance for the control of volatile organic compound (VOC) equipment leaks from the natural gas production industry are being promulgated under Section 111 of the Clean Air Act. These standards will apply to equipment leaks of VOC within new, modified, and reconstructed gas plant compressors and process units. This document summarizes the responses to public comments received on the proposed standards and the basis for changes made in the standards since proposal.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution Fugitive Emissions Natural Gas Production Pollution Control Standards of Performance Volatile Organic Compounds (VOC)	Air Pollution Control	13b

18. DISTRIBUTION STATEMENT Unlimited - Available to the public free of charge from U.S. EPA Library (MD-35) Research Triangle Park, NC 27711	19. SECURITY CLASS *(This Report)* Unlimited	21. NO. OF PAGES 122
	20. SECURITY CLASS *(This page)* Unlimited	22. PRICE

EPA Form 2220-1 (Rev. 4-77) PREVIOUS EDITION IS OBSOLETE

EPA-450/3-82-024b

Equipment Leaks of VOC in Natural Gas Production Industry - Background Information for Promulgated Standards

Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

May 1985

This report has been reviewed by the Emission Standards and Engineering Division of the Office of Air Quality Planning and Standards, EPA, and approved for publication. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use. Copies of this report are available through the Library Services Office (MD-35), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; or, for a fee, from the National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161.

ENVIRONMENTAL PROTECTION AGENCY

Background Information and Final Environmental Impact Statement for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants

Prepared by:

Jack R. Farmer 5/3/85

Jack R. Farmer (Date)
Director, Emission Standards and Engineering Division
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

1. The promulgated standards of performance will limit equipment leaks of VOC from new, modified, and reconstructed gas plant process units and compressors. Section 111 of the Clean Air Act (42 U.S.C. 7411), as amended, directs the Administrator to establish standards of performance for any category of new stationary source of air pollution that ". . . causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

2. Copies of this document have been sent to the following Federal Departments: Labor, Health and Human Services, Defense, Transportation, Agriculture, Commerce, Interior, and Energy; the National Science Foundation; the Council on Environmental Quality; State and Territorial Pollution Program Administrators; EPA Regional Administrators; Local Air Pollution Control Officials; Office of Management and Budget; and other interested parties.

3. For additional information contact:

   Ms. Dianne Byrne or Mr. Gilbert Wood
   Standards Development Branch (MD-13)
   U.S. Environmental Protection Agency
   Research Triangle Park, NC 27711
   Telephone: (919) 541-5578

4. Copies of this document may be obtained from:

   U.S. EPA Library (MD-35)
   Research Triangle Park, NC 27711
   Telephone: (919) 541-2777

   National Technical Information Service
   5285 Port Royal Road
   Springfield, VA 22161

TABLE OF CONTENTS

Section	Title	Page
	TABLE OF CONTENTS	v
	LIST OF TABLES	viii
	LIST OF FIGURES	ix
1.0	SUMMARY	1-1
	1.1 Introduction	1-1
	1.2 Summary of Changes Since Proposal	1-1
	1.3 Summary of Impacts of Promulgated Action	1-4
	1.4 Summary of Public Comments	1-5
2.0	NEED FOR STANDARDS	2-1
	2.1 Significance of Emissions and Public Health Impact	2-1
	2.2 Adequacy of Current Controls and Regulations	2-3
	2.3 Industry Growth, Industry Mobility, and Seasonal Considerations	2-5
3.0	BASIS FOR STANDARDS	3-1
	3.1 Introduction	3-1
	3.2 Valves	3-1
	3.3 Pumps	3-1
	3.4 Compressors	3-2
	3.5 Open-Ended Lines	3-2
	3.6 Pressure Relief Devices	3-2
	3.7 Sampling Connections	3-4

TABLE OF CONTENTS (Continued)

Section Title Page

4.0 FORMAT AND REQUIREMENTS OF STANDARDS 4-1
  4.1 Format of Standards 4-1
  4.2 Valves 4-1
  4.3 Pumps 4-4
  4.4 Compressors 4-5
  4.5 Open-Ended Lines 4-7
  4.6 Pressure Relief Devices 4-9
  4.7 Control Devices 4-13
  4.8 Leak Detection and Repair 4-18

5.0 APPLICABILITY OF STANDARDS 5-1
  5.1 Definitions 5-1
  5.2 Selection of Sources 5-7
  5.3 Selection of Affected Facilities 5-10
  5.4 Applicability Date 5-12
  5.5 Alaskan North Slope 5-13
  5.6 Small Plants 5-15

6.0 ENVIRONMENTAL IMPACTS 6-1
  6.1 Emission Reductions 6-1
  6.2 Leak Frequencies 6-4
  6.3 Emission Factors 6-5
  6.4 Model Plants 6-7
  6.5 Nonair Environmental Impacts 6-7

TABLE OF CONTENTS (Concluded)

Section	Title	Page
7.0	COST OF CONTROL	7-1
	7.1 General	7-1
	7.2 Compressors	7-3
	7.3 Pressure Relief Devices	7-6
	7.4 Control Devices	7-7
	7.5 Leak Detection and Repair	7-9
8.0	ECONOMIC IMPACTS	8-1
	8.1 Prices	8-1
	8.2 Industry Impacts	8-3
	8.3 Small Businesses	8-4
9.0	MODIFICATION AND RECONSTRUCTION	9-1
	9.1 Capital Expenditure	9-1
	9.2 Modification of Existing Sources	9-2
	9.3 Miscellaneous	9-3
10.0	TEST METHODS	10-1
	10.1 Leak Detection Methods	10-1
	10.2 Leak Definition	10-4
11.0	RECORDKEEPING AND REPORTING	11-1
	11.1 General	11-1
	11.2 Reporting	11-4
	11.3 Recordkeeping	11-5
12.0	MISCELLANEOUS	12-1

LIST OF TABLES

Number	Title	Page
1-1	Projected VOC Equipment Leak Emissions from Uncontrolled, Baseline, and NSPS Control Levels	1-6
1-2	List of Commenters on Proposed Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants	1-8
3-1	Control Costs per Megagram of VOC Reduced	3-3
7-1	Cost Effectiveness of Compressor Vent Control Systems for Model Plant B	7-5
7-2	Summary of Total Annual Costs to Perform Leak Detection and Repair Program at a 500-Component Gas Plant	7-12

LIST OF FIGURES

Number Title Page

5-1 Cost Effectiveness versus Plant Size for Small Plants 5-16

1.0 SUMMARY

1.1 INTRODUCTION

On January 20, 1984, the Environmental Protection Agency (EPA) proposed standards of performance for equipment leaks of volatile organic compounds (VOC) emissions from onshore natural gas processing plants (49 FR 2636) under the authority of Section 111 of the Clean Air Act. Public comments were requested on the proposal in the Federal Register. EPA received 37 comment letters on the proposed standards and statements from five speakers at the public hearing on March 7, 1984. Industry representatives submitted most of the comments. Also commenting was a vendor of safety equipment. The comments that were submitted, along with responses to these comments, are summarized in this document. This summary of comments and responses serves as the basis for the revisions made to the applicability and requirements of the standards between proposal and promulgation.

1.2 SUMMARY OF CHANGES SINCE PROPOSAL

The proposed standards were revised as a result of reviewing public comments. Changes were made in the following areas:

- Exemption for reciprocating compressors in wet gas service
- Revisions to flare requirements
- Definition of "in VOC service"
- Monitoring requirements for pressure relief devices at certain plants
- Provision for difficult-to-monitor valves in new units
- Leak detection and repair requirements for natural gas processing plants located in the North Slope of Alaska
- Alternative for determining a "capital expenditure"

1.2.1 Exemption for All Reciprocating Compressors in Wet Gas Service

At proposal, EPA exempted reciprocating compressors in wet gas service only if they were located at a gas plant that did not have an existing control device. The cost effectiveness of controlling such compressors was high due to the cost of installing and operating a control device. However, the cost effectiveness of controlling wet gas reciprocating compressors at plants with an existing control device ($1700 per megagram of VOC reduced) was considered reasonable, given that the average cost effectiveness (combining cost-effectiveness numbers for centrifugal and reciprocating compressors) was estimated to be much lower ($460 per megagram). However, since proposal, several industry representatives commented that many gas plants, especially small ones, will use reciprocating compressors almost exclusively. For such plants, the compressor control cost effectiveness would be essentially the same as the cost effectiveness for controlling only wet gas reciprocating compressors at plants with an existing control device (i.e., $1700 per megagram). This cost effectiveness, when considered representative of the overall compressor control costs for small plants, is judged to be unreasonably high. For this reason, the promulgated standards have been revised to exempt all wet gas reciprocating compressors. Reciprocating compressors used in natural gas liquids (NGL) service and all centrifugal compressors in wet gas or NGL service are still required to be equipped with closed vent systems, however, because they can be controlled at a reasonable cost effectiveness.

1.2.2 Revisions to Flare Requirements

The velocity and heating value requirements for flares have been changed since proposal of the standards to allow flares burning gas streams with high heating values to use high velocities. The final standards present equations for calculating the maximum permitted velocity for flares to provide for velocities up to 122 meters per second (m/sec) (400 feet per second (ft/sec)) depending on the gas heat content. The purpose of the equations is to allow streams with heat contents greater than 11.2 megajoules per standard cubic meter (MJ/scm) (300 British thermal units per standard cubic foot (Btu/scf)) to be flared at higher velocities, while ensuring a VOC destruction efficiency that reflects best demonstrated technology (BDT). If the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf), then a flare exit velocity of 122 m/sec (400 ft/sec) will be accepted. The basis for these changes in the flare requirements is discussed in Section 4.7.

1.2.3 Definition of "In VOC Service"

The EPA received numerous requests from commenters for raising the VOC concentration for "in VOC service" from 1 weight percent to 10 weight percent VOC. The commenters stated that a 1 weight percent VOC limit would cause many dry (residue) gas streams with low VOC content to be regulated, and, as a result, poor cost effectiveness.

The EPA intended to exempt dry gas in the proposed standards due to the fact that dry gas has very low (generally less than 1.0 weight percent) VOC content and, therefore, is generally not cost effective to control. The EPA did, however, intend for wet gas (inlet or field gas) components to be regulated, since components in wet gas service have a high VOC content and are cost effective to control. At proposal, EPA selected 1.0 weight percent VOC as the VOC service definition to exclude dry gas, while assuring that wet gas streams would be regulated.

Commenters on the proposed standards provided data indicating that 1 weight percent was not an appropriate limit, since dry gas streams can contain more than 1 weight percent VOC. The EPA agrees that it is difficult to define a range of VOC concentrations for either wet gas or dry gas streams and, therefore, has decided to include equipment in wet gas service by covering them as a class.

Considering that gas plant streams, other than wet gas streams, containing less than 10 weight percent VOC (dry gas or VOC/non-VOC mixtures) would not be cost effective to control, a VOC concentration limit of 10 weight percent was selected as a representative limit for the "in VOC service" definition. Therefore, the definition of "in VOC service" has been changed in the promulgated standards to refer to a 10 weight percent VOC content.

1.2.4 Monitoring Requirements for Pressure Relief Devices

Since proposal, EPA has reviewed comments concerning the monitoring of pressure relief devices following pressure release. Commenters representing small nonfractionating gas plants claimed that the requirement to monitor pressure relief devices within 5 days of a pressure release was burdensome because of the unavailability of monitoring instruments at the plant and problems in scheduling contractor assistance in such a short time. Based on these comments, EPA decided to allow owners and operators of nonfractionating plants which are monitored only by non-plant personnel to monitor pressure relief devices the next time the monitoring personnel are on-site or within 30 days of a pressure release, whichever comes first, instead of within 5 days.

1.2.5 Provision for Difficult-to-monitor Valves in New Units

At proposal, EPA allowed annual monitoring of difficult-to-monitor valves in units covered by the modification or reconstruction provisions, but there was no similar provision for difficult-to-monitor valves in new units. Commenters stated that all new units could not be designed to eliminate difficult-to-monitor valves. Upon reviewing these comments, EPA decided to allow plant owners or operators to designate up to 3 percent of the total number of valves in a new unit as difficult to monitor. Based on existing units, about 3 percent of the total number of valves may be difficult to design to be accessible in new units without significant additional costs.

1.2.6 Leak Detection and Repair Requirements for Natural Gas Processing Plants Located in the North Slope of Alaska

The EPA reviewed comments concerning natural gas plant operations in the North Slope of Alaska and determined that the costs to comply with certain aspects of the [illegible]posed standards can be unreasonable. Leak detection and repair programs incur higher labor, administrative, and support costs at plants that are located at great distances from major population centers and particularly those that experience extremely low temperatures as in the arctic. Thus, EPA decided to exempt plants located in the North Slope of Alaska from the routine leak detection and repair requirements. The EPA excluded these plants only from the routine leak detection and repair requirements because the costs of the other requirements are reasonable.

1.2.7 Alternative for Determining a "Capital Expenditure"

The annual asset guideline repair allowance (AAGRA) and the original cost basis are used to define capital expenditures (see 40 CFR 60.2). The definition of AAGRA is specified by the Internal Revenue Service (IRS), and its use has not changed despite tax law revisions in

1982. In response to comments concerning the basis for determining a capital expenditure, EPA has amended the definition of a capital expenditure to provide an alternative procedure for determining the original cost basis. This procedure will allow plant personnel to use a percentage of replacement costs rather than original costs to determine capital expenditure; however, this procedure does not affect the coverage of the standards. Details of the alternative are discussed in Chapter 9.

1.3 SUMMARY OF IMPACTS OF PROMULGATED ACTION

1.3.1 Alternatives to Promulgated Action

The regulatory alternatives are discussed in Chapter 6 of the background information document (BID) for the proposed standards EPA-450/3-82-024a. These regulatory alternatives reflect the different levels of emission control that were used in the selection of best demonstrated technology (BDT), considering costs, nonair quality health, and environmental and economic impacts for sources of equipment leaks of VOC in the natural gas processing industry. No changes have been made in the regulatory alternatives since proposal.

1.3.2 Environmental Impacts of Promulgated Action

Environmental impacts of the standards are described in Chapter 7 of the BID for the proposed standards. Changes made in the standards since proposal affect the estimated VOC emission reduction. These changes, which will reduce the industry-wide emission reduction of the standards, include a change in the estimated compressor service split, the exemption for reciprocating compressors in wet gas service, and the effects of the Control Techniques Guideline (CTG) requirements (EPA-450/3-83-007), which have been published since proposal of the standards. The EPA has revised the estimate of VOC emissions that will be reduced by the standards.

The promulgated standards will reduce equipment leaks of VOC from newly constructed, modified, and reconstructed facilities by 16,100 megagrams (Mg) in the fifth year of implementation of the standards, a reduction of emissions from 22,000 Mg of VOC per year (Mg/yr) to 5,900 Mg/yr. This reduction represents a 73 percent decrease in emissions from the current industry baseline level of emissions. The basis of the revised estimate of VOC emissions that will be reduced by the standards is discussed in Docket Item IV-B-9. The water quality and solid waste impacts have not changed significantly as a result of the revised emission estimates.

With the changes noted above, the analysis of the environmental impacts in the BID for the proposed standards now becomes the final Environmental Impact Statement for the promulgated standards.

1.3.3 Energy and Economic Impacts of Promulgated Action

Section 7.5 of the BID for the proposed standards describes the energy impacts of the standards. The revisions made in the standards do not change significantly the energy impacts of the standards because the energy value and crude oil equivalent of VOC emission reductions are about the same as they were at proposal.

Chapters 8 and 9 of the BID for the proposed standards describe the cost and economic impacts of the proposed standards. Since proposal, the cost analysis of the standards has been revised to reflect the changes discussed above that have been made since proposal. The industry-wide cost of the standards is lower than the estimate at proposal because of the effects of CTG requirements for onshore natural gas processing plants (published since proposal) in the fifth year of the standards and because of the exemption of reciprocating compressors in wet gas service from the standards since proposal. The promulgated standards will require an industry-wide capital investment and net annualized cost of approximately $6.2 million and $1.5 million, respectively, for newly constructed, modified, and reconstructed facilities in the fifth year of implementation of the standards. The basis of the revised industry-wide costs is discussed in Docket Item IV-B-9. As discussed in Chapter 8 of this document, the economic impact of the promulgated standards remains reasonable.

1.3.4 Other Considerations

1.3.4.1 Irreversible and Irretrievable Commitment. Section 7.6.1 of the BID for the proposed standards concludes that the standards will not result in any irreversible or irretrievable commitment of resources. It was also concluded that the standards should help to save resources due to the energy savings associated with the reduction in emissions. These conclusions remain unchanged since proposal.

1.3.4.2 Environmental Impacts of Delayed Standards. Table 1-1 of this document summarizes the environmental impacts associated with delaying promulgation of the standards. The air impacts have been revised since proposal as explained in Table 1-1. Uncontrolled and controlled emissions would occur at the rates shown for each of the 5 years. Fifth-year emission reductions from the uncontrolled level and baseline level are presented.

1.4 SUMMARY OF PUBLIC COMMENTS

EPA received 37 comment letters and statements from five speakers at the public hearing on the proposed standards and the BID for the proposed standards. Comments from the public hearing on the proposed standards were recorded, and a transcript of the public hearing was placed in the project docket along with all public comment letters. At the request of some of the commenters, the comment period was extended 60 days to allow more time for review and comment. A list of commenters, their affiliations, and the EPA docket item number assigned to their correspondence is given in Table 1-2.

TABLE 1-1. PROJECTED VOC EQUIPMENT LEAK EMISSIONS FROM UNCONTROLLED, BASELINE, AND NSPS CONTROL LEVELS

	Total VOC Emissions Projected, Gg/yr					
	(Proposal Basis)		(Promulgation Basis)			
YEAR	Uncontrolled[a]	Proposed NSPS[b]	Uncontrolled[c]	Baseline[d]	Proposed NSPS[e]	Final NSPS[f]
1983	5.1	1.2	5.1	4.7	1.2	1.3
1984	10.2	2.4	10.1	9.5	2.5	2.6
1985	15.3	3.6	15.2	14.2	3.7	3.9
1986	19.5	4.5	19.3	18.1	4.7	4.9
1987	23.6	5.5	23.5	22.0	5.7	5.9
5th year (1987) Emission Reduction from Uncontrolled	--	18.1	--	1.5	17.8	17.6
5th year (1987) Emission Reduction from Baseline	--	--	--	--	16.3	16.1
Cost effectiveness ($/Mg)	--	140	--	--	150	93

[a] From Docket Item IV-B-9. The uncontrolled emissions assumed at proposal that all natural gas processing plants are operated with no regulations for control of equipment leaks of VOC.

[b] Emission levels under the proposed standards are based on Docket Item II-B-38, which presents the controlled emission levels for each model plant, and Table 7-5 of the BID for the proposed standards, which presents the anticipated number of model plants affected. The memo did not take into account, however, that one-half of all reciprocating compressors in wet gas service would be exempt, which was assumed at proposal. Also assumes that 34 percent of all compressors are in NGL service and that 66 percent are in wet gas service.

[c] Since proposal, as explained in Docket Item IV-B-9, the uncontrolled emission estimates have been revised due to a change in the assumed distribution of compressor service. This results in a change in emissions of 100 Mg/yr in 1987 from the uncontrolled level reported at proposal as there are now assumed to be more compressors in wet gas service and less in NGL service.

TABLE 1-1

PROJECTED VOC EQUIPMENT LEAK EMISSIONS FROM UNCONTROLLED, BASELINE, AND NSPS CONTROL LEVELS (Concluded)

[d] The baseline level of control assumes that 10 percent of new gas plants will be built in ozone nonattainment areas and will be subject to requirements similar to those in the CTG for natural gas processing plants (Docket Item II-J-1). Calculated as described in Docket Item IV-B-9.

[e] Emission levels under the proposed standards reflect the fact that wet gas reciprocating compressors in plants with an existing control device were required to be controlled. The final NSPS does not require controls on these compressors. However, emissions under the proposed standards are higher than assumed at proposal because of a change in the ratio of compressors in NGL and wet gas service (i.e., 50% of all compressors are exempt wet gas reciprocating units, and the remaining 50% are split equally between wet gas centrifugal units and NGL units of both types). Under these conditions, 25 percent of all compressors would be exempt from the proposed standards, since they would be wet gas reciprocating units at plants without a control device.

[f] Revised emission levels from implementing the final standards are based on Docket Item IV-B-9 and are slightly higher than the emission levels under the proposed standards as a result of the exemption of all wet gas reciprocating compressors. This exemption decreases the emission reduction from the proposal level by 200 Mg/yr in 1987, resulting in a total emission reduction of 16,100 Mg/yr from the baseline level of control.

TABLE 1-2. LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOC FROM ONSHORE NATURAL GAS PROCESSING PLANTS

Commenter and Affiliation	Docket Item No.
1. Mr. J.D. Reed Standard Oil Company (Indiana) 200 East Randolf Drive Chicago, IL 60601	IV-D-1
2. Mr. Louis R. Harris BS & B Safety Systems, Inc. 7455 East 46th Street P.O. Box 470590 Tulsa, OK 74147-0590	IV-D-2
3. Mr. Rodney D. Long Minerals, Inc. P.O. Box 1320 Hobbs, NM 88240	IV-D-3
4. Mr. Greg Lewis Liquid Energy Corporation 2001 Timberlock Place P.O. Box 4000 The Woodlands, TX 77380	IV-D-4 IV-D-21
5. Mr. J.D. Geiger Aminoil, USA P.O. Box 94193 Houston, TX 77292	IV-D-5 IV-D-23
6. Mr. R.E. Cannon Gas Processors Association 1812 First Place Tulsa, OK 74103	IV-D-6 IV-D-26
7. Mr. John J. Moon Phillips Petroleum Company Bartlesville, OK 74004	IV-D-7 IV-D-31
8. Mrs. Laura G. Daniel Conoco, Inc. P.O. Box 2197, Suite 450 RT Houston, TX 77252	IV-D-8 IV-D-36

TABLE 1-2. LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOC FROM ONSHORE NATURAL GAS PROCESSING PLANTS (continued)

Commenter and Affiliation	Docket Item No.
9. Mr. H.K. Holland, Jr. Mobil Oil Corporation 150 East 42nd Street New York, NY 10017	IV-D-9
10. Mr. A.G. Smith Shell Oil Company One Shell Plaza P.O. Box 4320 Houston, TX 77210	IV-D-10
11. Mr. Robert H. Lovell Mountain Fuel Supply Company 180 East First South P.O. Box 11368 Salt Lake City, UT 84139	IV-D-11 IV-D-11a
12. Mr. A.E. Middents Western Slope Gas Company One Park Central - 1515 Arapahoe Street P.O. Box 840 Denver, CO 80201	IV-D-12
13. Mr. Peter W. McCallum The Standard Oil Company (Ohio) Midland Building Cleveland, OH 44115-1098	IV-D-13
14. Mr. B.L. Walters, Jr. Marathon Oil Company Findlay, OH 45840	IV-D-14
15. Mr. H.B. Barton Exxon Company, U.S.A. P.O. Box 2180 Houston, TX 77001	IV-D-15
16. Mr. W.W. Cofield Transco Energy Company 2700 Post Oak Boulevard P.O. Box 1396 Houston, TX 77251	IV-D-16

TABLE 1-2. LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOC FROM ONSHORE NATURAL GAS PROCESSING PLANTS (continued)

Commenter and Affiliation	Docket Item No.
17. Mr. Steven E. Kurmas, P.E. Michigan Consolidated Gas Company 500 Grinswold Street Detroit, MI 48226	IV-D-17
18. Mr. P.K. Smith, Jr. Kerr-McGee Corporation Kerr-McGee Center Oklahoma City, OK 73125	IV-D-18
19. Mr. H. Schuyten Chevron U.S.A., Inc. 575 Market Street P.O. Box 7643 San Francisco, CA 94120-7643	IV-D-19
20. Mr. J.P. Keehan Mobil Oil Corporation 150 East 42nd Street New York, NY 10017	IV-D-20
21. Mr. L. James Anderson Union Oil of California Union Oil Center Box 7600 Los Angeles, CA 90051	IV-D-22
22. Mr. J. Donald Annett Texaco U.S.A. 1050 17th Street, N.W. Suite 500 Washington, D.C. 20036	IV-D-24
23. Mr. George H. Lawrence The American Gas Association 1515 Wilson Boulevard Arlington, VA 22209	IV-D-25
24. Mr. Jack Swenson Rocky Mountain Oil and Gas Association, Inc. 345 Petroleum Building Denver, CO 80202	IV-D-27

TABLE 1-2. LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOC FROM ONSHORE NATURAL GAS PROCESSING PLANTS (continued)

Commenter and Affiliation	Docket Item No.
25. Mr. Stuart C. Mut ARCO Oil and Gas Company P.O. Box 2819 Dallas, TX 75221	IV-D-28
26. Mr. Frank J. Duffy Northern Gas Products Company 2223 Dodge Street Omaha, NE 68102	IV-D-29
27. Mr. R.J. Cinq-Mars Cities Service Oil and Gas Corporation Box 300 Tulsa, OK 74102	IV-D-30
28. Dr. Howard Reiquam, Ph.D. El Paso Natural Gas Company P.O. Box 1492 El Paso, TX 79978	IV-D-32
29. Mr. P.J. Early Amoco Production Company 200 East Randolf Drive P.O. Box 5340A Chicago, IL 60680	IV-D-33
30. Mr. Lawrence J. Ogden Interstate Natural Gas Association of America 1660 L Street, N.W. Washington, D.C. 20036-5611	IV-D-34
31. Mr. John G. Blackburn, Jr. American Petroleum Institute 1220 L Street, N.W. Washington, D.C. 20005	IV-D-35
32. Mr. L.T. Reed Warren Petroleum Company P.O. Box 1589 Tulsa, OK 74102	IV-D-37

TABLE 1-2. LIST OF COMMENTERS ON PROPOSED STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOC FROM ONSHORE NATURAL GAS PROCESSING PLANTS (concluded)

Commenter and Affiliation	Docket Item No.
Public Hearing	
33. Mr. Jim Anderson Gas Processors Association 1812 First Place Tulsa, OK 74103	IV-F-1a
34. Mr. William S. Taylor Union Texas Petroleum Corporation P.O. Box 2120 Houston, TX 77252	IV-F-1b
35. Mr. Gary Reed (Representing the Independent Petroleum Association of America) Texas Oil & Gas Corp. First City Center Lock Box No. 10 Dallas, TX 75201	IV-F-1c
36. Mr. Scott Ronzio ARCO Alaska, Inc. Anchorage, Alaska 99510	IV-F-1d
37. Mr. W.J. Woodruff (Representing American Petroleum Institute) Phillips Petroleum Company Bartlesville, OK 74004	IV-F-1e*

---

*At the public hearing, API requested that its oral and written comments to EPA on the proposed standard and the related CTG be incorporated in the record. These API comments relevant to the basis of the promulgated standards have been included in this document. The docket items are listed in parentheses as "II-B-xx" or "II-D-xx" in the appropriate comment summaries.

The comments have been categorized under the following topics:

Need for Standards (Section 2)
Basis for Standards (Section 3)
Format and Requirements of Standards (Section 4)
Applicability of Standards (Section 5)
Environmental Impacts (Section 6)
Control Costs (Section 7)
Economic Impacts (Section 8)
Modification and Reconstruction (Section 9)
Test Methods (Section 10)
Recordkeeping and Reporting (Section 11)
Miscellaneous (Section 12)

The comments, the issues they address, and EPA's responses are discussed in the following sections of this document.

2.0 NEED FOR STANDARDS

This chapter summarizes public comments and responses to comments on the need for the standards. Included are comments on the significance of emissions and public health benefit of the standards, the adequacy of current controls and regulations, industry growth and mobility, and effects of seasonal variations in ozone formation.

2.1 SIGNIFICANCE OF EMISSIONS AND PUBLIC HEALTH IMPACT

Comment: Many commenters (IV-D-3; IV-D-20; IV-D-29; IV-D-31; IV-F-4) questioned the significance of VOC emissions from gas plants. The commenters questioned EPA's contention (or judgment) that VOC emissions from natural gas plants contribute to air pollution significantly enough to reasonably be expected to endanger the public health and welfare and to violate the National Ambient Air Quality Standards (NAAQS) for ozone. Commenter IV-D-3 questioned whether propane and heavier gases break down in sunlight and air or whether they are dispersed sufficiently so as to be of no significance. Commenter IV-F-4 claimed that natural gas processing plants are not large emitters of VOC, particularly with the exclusion of methane and ethane. Commenter IV-D-27 specifically felt that the oil and gas industry in the Rocky Mountain region is not a significant contributor of VOC emissions.

Commenter IV-D-31 added that VOC as a class of compounds are not criteria pollutants. Hydrocarbons as a class of pollutants under the NAAQS were determined by EPA not to pose a direct threat to the public health or welfare at typical ambient levels, and the NAAQS for hydrocarbons were revoked on January 5, 1983.

Response: In response to the commenter's (IV-D-3) question about the fate of propane and heavier gases when exposed to sunlight and air, these gases do break down in the presence of sunlight and air; however, they remain in the atmosphere long enough to participate in photochemical reactions. Consequently, propane and heavier gases pose a significant threat to the environment.

As reported in Table 1-1 of this document, an estimated 20,100 megagrams of VOC per year (Mg/yr) would be emitted from about 220 new, modified, or reconstructed onshore natural gas processing plants in 1987 if no additional controls were implemented by the industry. On an individual plant basis, a typical medium-sized gas plant having nonfractionating refrigeration units or fractionating cryogenic units is estimated to emit about 100 Mg/yr assuming no additional controls. EPA considers both nationwide and individual plant emissions from natural gas processing plants to be significant based on the above estimates and on the listing of crude oil and natural gas production on the EPA Priority List (40 CFR 60.16, amended at 47 FR 951, January 8, 1982).

In consideration of the significant quantity of VOC emissions from natural gas processing plants, EPA examined the "public health and welfare" effects associated with these emissions. The Administrator clearly documented the need to regulate VOC to protect public health and welfare in the EPA publication "Air Quality Criteria for

Ozone and Other Photochemical Oxidants" (EPA-600/8-78-004, April 1978). VOC emissions are precursors to ozone formation, and ozone has been determined to be harmful to human health and has been shown to have environmental effects on vegetation and materials as well as other damage to the ecosystem. Some of the health and welfare effects associated with ozone exposure are the following:

Human health effects - Ozone exposure has been shown to cause increased rates of respiratory symptoms, such as coughing, wheezing, sneezing, and shortness of breath; increased rates of headache, eye irritation, and throat irritation; and physiological damage to red blood cells. Experimental data link ozone exposure to human cell damages known as chromosomal aberrations.

Vegetation effects - Reduced crop yields as a result of damages to leaves and/or plants are documented for several crops, including citrus, grapes, and cotton. The reduction in crop yields is shown to be linked to the level and duration of ozone exposure.

Materials effects - Ozone exposure is shown to accelerate the deterioration of organic materials, such as plastics and rubber (elastomers), textile dyes, fibers, and certain paints and coatings.

Ecosystem effects - Continued ozone exposure is linked to structural changes of forests, such as the disappearance of certain tree species (Ponderosa and Jeffrey pines) and death of some types of vegetation. Hence, ozone causes stress to the ecosystem.

Commenter IV-D-31 correctly states that the NAAQS for hydrocarbons were revoked. The revocation notice (48 FR 628), however, clearly points out that "... nonetheless, hydrocarbons should continue to be controlled or restricted because of their contribution to the formation of ozone and the resultant health and welfare effects of this pollutant and other photochemical oxidant products." In addition, the notice states that specific hydrocarbons (including VOC) which are shown to cause adverse effects can be regulated separately. The notice does not restrict EPA or State authority in regulating emissions of hydrocarbon as a class, particularly hydrocarbon compounds or any other VOC that may be found to pose a threat to public health or welfare.

Comment: One commenter (IV-D-3) questioned if the judgment of the Administrator was a valid reason for implementing standards and asked what facts back up this judgment.

Response: The judgment of the Administrator is a valid reason for implementing standards. The Clean Air Act mandates that the Administrator list a source category "... if in his judgment it [the source category] causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare" [Section 111(b)(1)(A)]. The facts considered by the Administrator in making this judgment include, but are not limited to, the quantity of pollutant(s) emitted and the health and welfare effects associated with the pollutant. The quantity of VOC emitted by the natural gas processing industry and the health and welfare effects associated with ozone exposure are discussed in the response to the previous comment.

2.2 ADEQUACY OF CURRENT CONTROLS AND REGULATIONS

Comment: A number of commenters questioned the need for the standards because, in their opinions, equipment leaks of VOC in this industry may be adequately controlled by other regulations or approaches. Several commenters (IV-D-12; IV-D-20; IV-D-31) felt that the proposed standards are not necessary in areas where ozone ambient air standards and Prevention of Significant Deterioration (PSD) requirements are being met. Commenters IV-D-12 and IV-D-20 maintained that, while large, urban, non-attainment areas might need to control VOC emissions strictly, most natural gas plants (particularly in the West) are located in remote, rural areas far from major population centers or ozone nonattainment areas. Similarly, another commenter (IV-F-1a) claimed that the effects of the proposed standards would be regional, citing a statement from the Oil and Gas Journal (July 18, 1983) that 90 percent of all gas plants and industry capacity is located in five States.

Commenter IV-D-24 maintained that a State and local approach to regulating gas plants would better take into account the many differences among gas plants and result in cheaper and more effective pollution controls. The commenter noted that Ventura County, California, has a fugitive emissions program covering gas plants and that the South Coast Air Quality Management District (Los Angeles, Orange, Riverside, and San Bernardino Counties) and Kern County are in the process of establishing similar type regulations. The commenter was also concerned that the proposed standards could remove a potential source of hydrocarbon offsets in counties currently or predicted to become attainment for ozone (i.e., Santa Barbara and San Luis Obispo). Commenter IV-D-31 added that there is ample EPA technical guidance (e.g., CTG and BID documents for VOC equipment leaks from natural gas processing plants) available to enable States and local agencies to make reasoned determinations of best available control technology (BACT) under PSD regulations if located in an attainment area and lowest achievable emission rate (LAER) if located in a nonattainment area.

Response: In setting new source performance standards under Section 111 of the Clean Air Act, location of the industry in attainment or nonattainment areas is not relevant. Location of an industry in an attainment or nonattainment area is relevant to achieving the National Ambient Air Quality Standards (NAAQS) under Sections 109 and 110 of the Clean Air Act. The NSPS complements the ambient air quality-based rules as a means of achieving and maintaining the NAAQS and PSD requirements, while on a broader basis it prevents new sources from making air pollution problems worse, regardless of the existing quality of ambient air. Similarly, in most cases State and local regulations complement the NSPS. The intent of Congress in establishing NSPS was to establish a uniform level of stringency nationwide, thereby preventing States with lenient air pollution requirements from attracting new industry construction. The standards will limit VOC emissions from newly constructed, modified, and reconstructed facilities in natural gas processing plants and will result in emission reductions well into the future. Even though these reductions may not bear directly now on attainment or nonattainment of NAAQS for ozone, they will make room for future industrial growth while attainment and nonattainment areas would benefit from these standards.

Comment: One commenter (IV-D-3) stated that, in his opinion, the proposed standards represent a prime example of government intervention in an industry that is already overtaxed and overburdened with rules and regulations. The industry has proven it can regulate itself and has done a commendable job of self-regulation.

Response: The commenter's assertions regarding overtaxation, overburdening, and self-regulation are unclear, and he provided no supporting information about his claims. In the absence of the standards, the natural gas processing industry will emit about 20,100 Mg/yr of VOC emissions from equipment leaks, which reflects normal existing gas plant operations with self-regulation plus State regulations (Table 1-1). With the control requirements that will be implemented by the standards, gas plants can achieve significant emission reductions at reasonable costs. A total of 14,600 Mg/yr of VOC emissions are expected to be reduced nationwide as a result of implementation of the control techniques required by the standards. This represents an emission reduction of 74 percent from existing levels, which already reflect self-regulation plus State regulations.

Comment: One commenter (IV-D-12) pointed out that the industry has several incentives to control VOC emissions. The entire justification of the processing plant, according to the commenter, is to extract liquid and heavy gaseous hydrocarbons for sale. Given the current value of these hydrocarbons, the commenter maintained that the industry has a large incentive to capture and sell as large a quantity as reasonably possible. The commenter also noted the incentive of preventing safety hazards associated with leak control.

Another commenter (IV-D-11) indicated that his company had spent considerable time, effort, and money to establish leak prevention and control procedures to comply with current regulations, and thus felt that natural gas plant VOC leaks were adequately controlled already.

Similarly, another commenter (IV-D-22) noted that plant personnel will detect most significant leaks visually or by sound during routine daily inspections, and that it is standard operating procedure to repair leaking equipment as soon as possible. The commenter added that individual component surveys using a hydrocarbon detector or any other type of instrument would be extremely time consuming and in many cases impractical.

Response: EPA concurs with the first commenter on the industry incentives to control emissions. These incentives form the basis for the recovery credits used by EPA in calculating the net costs for compliance with the standards.

The commenters imply that the standards are unnecessary due to the industry's own safety and economic incentives to eliminate leaks or due to industry practices that have been implemented to comply with current regulations. However, the data base used in development of the standards shows that significant emissions do occur from equipment leaks at natural gas processing plants. As given in Table 7-2 of the BID for proposed standards, adjusted for the revised compressor seal emission factor, the baseline emissions for a typical new gas plant (Model Plant B) would be 274 kg VOC/day (100 Mg/yr). The data were based on field testing of currently operating gas plants and reflect the emission levels remaining after industry leak prevention measures have been taken. The leak detection and repair programs and equipment requirements of the standards are aimed at reducing as many of the leaks as possible in a cost-effective manner and are expected to reduce VOC emissions by about 74 percent.

The commenter's questions on the practical aspects of leak monitoring are addressed in Chapters 4, 7, and 10.

2.3 INDUSTRY GROWTH, INDUSTRY MOBILITY, AND SEASONAL CONSIDERATIONS

Comment: Two commenters (IV-D-3; IV-D-29) questioned the need to implement VOC regulations based on projections of growth in the industry. One commenter (IV-D-3) reasoned that if natural gas production is expected to decline as stated in Chapter 9 of the BID for the proposed standards, air quality would improve without regulations.

The other commenter (IV-D-29) indicated that although a few additional plants may be built, liquid gas production is on the decline. In the commenter's opinion growth projections should be based on liquids production, which are the source of VOC leaks, and not the number of plants.

Response: The commenters' opinions are that the standards are not necessary because emissions will decrease without standards due to an expected decline in natural gas production and that growth projections should be based on production instead of number of plants. The decrease in natural gas production is not relevant to the need for new source performance standards. The necessity of the standards is based on projected growth within the industry and the potential for long-term improvement in air quality. Even though older gas plants may be shutdown, new gas plants will be built, as the second commenter correctly pointed out. Contrary to the commenter's opinion, the projected number of new plants is the appropriate measure for the impacts of the standards, as emissions reductions are achievable as new facilities become regulated. The general goal of NSPS is to require new facilities to incorporate best demonstrated technology as they are being constructed. EPA has estimated that 180 newly constructed and 40 modified and reconstructed gas plants will be affected by the standards through 1987. These plants can achieve significant emission reductions at reasonable costs.

Comment: Several commenters (IV-D-26, IV-D-29; IV-D-31; IV-D-35) contended that national standards for natural gas processing are not mandated because, among other reasons, natural gas plants are not geographically mobile and must locate near the source of gas. As such, States cannot compete for gas processing plants based on relaxed air quality standards.

Response: The considerations upon which the standards are based, as required by Section 111, include the quantity of air pollutant emissions from the source category, the extent to which the pollutant may reasonably be anticipated to endanger public health or welfare, and the availability of a demonstrated system of continuous emission reduction considering costs, nonair quality health and environmental impacts, and energy requirements. Therefore, mobility and competitive nature of the industry are not the only criteria that were considered. The first two factors, quantity of emissions and public health and welfare impacts, support the listing of this source category as discussed in Section 2.1.

Comment: One commenter (IV-D-31) stated that ozone formation is accepted by the scientific community as being a seasonal phenomenon, and that a review of the information pertaining to the formation of ozone and the demonstrated lack of adverse public health or welfare effects due to VOC emissions per se would lead to the conclusion that VOC emissions cannot be considered to endanger the public health or welfare during the months of October through April.

Since one of the underlying premises of the NSPS program as embodied in Section 111 of the Clean Air Act is that the source category being regulated emits a pollutant which can reasonably be anticipated to endanger the public health or welfare, the commenter recommended that, at a minimum, the scope of the NSPS be limited to the months of May through September, during which time there would at least be some potential for environmental benefit.

Response: Sections 111(a)(1) and 302(1) of the Clean Air Act require that NSPS reflect systems of continuous emission reduction. As explained elsewhere, these standards reflect such systems, which are operable throughout the year.

3.0 BASIS FOR STANDARDS

3.1 INTRODUCTION

Section 111 of the Clean Air Act, as amended, requires that standards of performance be based on the best system of continuous emission reduction that has been adequately demonstrated, considering costs, nonair quality health and environmental impacts, and energy requirements. The following sections present the basis for the promulgated standards for each type of equipment and any changes in the basis since proposal. The selection of the basis for the promulgated standards was based on an analysis of the VOC emission reductions, control costs, the cost effectiveness, and the incremental cost effectiveness for the control techniques considered. These impacts are summarized in Table 3-1.

3.2 VALVES

In selecting the basis of the standards for valves, EPA considered quarterly and monthly monitoring periods. Each of these intervals was compared in terms of the emission reduction achievable and cost effectiveness of the leak detection and repair program as presented in Appendix H of the BID for the proposed standards. At proposal, monthly monitoring was selected as the basis of the standards for valves because it achieves the largest emission reduction, 40.4 Mg per year for Model Plant B. The EPA also judged that monthly monitoring has a reasonable cost effectiveness, $7 per Mg. However, EPA also recognized at proposal that some valves have lower leak occurrence rates than others. Monthly monitoring of valves that do not leak for 2 consecutive months was judged to be unreasonable when compared to the additional emission reduction achieved by monthly monitoring over quarterly monitoring. Therefore, although EPA proposed that leak detection and repair programs include monthly monitoring for valves, the proposed standards allowed quarterly monitoring for valves that have been found not to leak for 2 successive months. The annual emission reduction achieved by this monthly/quarterly implementation would be 37.7 Mg for Model Plant B. The cost effectiveness and incremental cost effectiveness would be a credit of $100/Mg and a cost of $240/Mg, respectively. The promulgated standards are based on monthly/quarterly implementation, which was allowed at proposal.

3.3 PUMPS

In selecting the basis for pump requirements, EPA considered quarterly leak detection and repair, monthly leak detection and repair, and the installation of dual mechanical seals. As with valves, the three alternative control levels were examined to determine the achievable emission reduction, the net cost of the control technique, and the resulting cost effectiveness. Also examined was the incremental cost effectiveness resulting from dividing the increased cost of the next more stringent control technique by the resulting emission reduction increase.

Although dual mechanical seals provided the greatest emission reduction (2.6 Mg/yr for Model Plant B) for pumps, the cost effectiveness ($4,900/Mg) and incremental cost effectiveness ($31,000/Mg) were considered unreasonable. Monthly monitoring, however, resulted in emission reductions of 2.3 Mg/yr, at a cost effectiveness of $610/Mg, which EPA considered reasonable. The incremental cost effectiveness of monthly monitoring over quarterly monitoring, $800/Mg, was also considered reasonable. As such, monthly monitoring was selected as the basis for the proposed standards, and remains the basis for the promulgated standards.

3.4 COMPRESSORS

The requirements for compressors have been changed since proposal to exempt all reciprocating compressors in wet gas (field gas) service. In preparing the basis for the proposed standards, EPA averaged the cost effectiveness for reciprocating and centrifugal compressors (based on one half of all compressors being centrifugal), and wet gas and natural gas liquids (NGL) service (based on 34 percent of all compressors being in NGL service and 66 percent of all compressors being in wet gas service). Since the resulting cost effectiveness ($460/Mg) was considered reasonable, EPA required the installation of closed vent systems on all compressors except wet gas reciprocating compressors in plants without a control device.

Table 3-1 shows the emission reductions and cost effectiveness for a closed vent system for wet gas and NGL reciprocating and centrifugal compressors. The EPA considers the average cost effectiveness ($1950/Mg) of control systems on all wet gas reciprocating compressors at plants with and without a control device to be unreasonable and, therefore, has exempted these compressors from the promulgated standards. Reciprocating compressors in NGL service and centrifugal compressors in wet gas or NGL service can be equipped with closed vent and control systems at a reasonable cost effectiveness ($250/Mg, $500/Mg, and $64/Mg, respectively) and remain subject to the requirements of the promulgated standards.

3.5 OPEN-ENDED LINES

The basis for the promulgated standards for open-ended lines remains the same as the basis at proposal. The EPA estimated that capping or adding a second valve to all open-ended lines will reduce emissions from a typical (Model Plant B) plant by 19 Mg/yr, while saving the industry $103/Mg.

3.6 PRESSURE RELIEF DEVICES

The basis for the standards for pressure relief devices is a routine leak detection and repair program with quarterly monitoring. In selecting standards for pressure relief devices, EPA considered three regulatory alternatives, including the selected quarterly leak detection and repair program, a monthly leak detection and repair program, and the installation of rupture disks upstream of relief devices to prevent emissions.

TABLE 3-1. CONTROL COSTS PER MEGAGRAM OF VOC REDUCED[a]

Fugitive Emission Source	Control technique[b]	Emission Reduction[c], Mg/yr	Average[d], $/Mg	Incremental[e], $/Mg
Pressure relief devices	Quarterly leak detection and repair[f]	0.95	(610)[g]	(610)
	Monthly leak detection and repair	1.0	0	5,800
	Rupture disks	1.5	6,800	22,000
Compressors[h]				
reciprocating-wet gas	Closed vent and seal system	4.2	1,950[j]	1,950
reciprocating-NGL	Closed vent and seal system[f]	33	250[j]	250
centrifugal-wet gas	Closed vent and seal system[f]	4.2	500[j]	500
centrifugal-NGL	Closed vent and seal system[f]	33	64[j]	64
Open-ended valves and lines	Caps on open ends[f]	19	(103)	(103)
Sampling connections	Closed purge sampling[i]	0.22	7,000	7,000
Valves	Quarterly leak detection and repair	7.3	(104)	(104)
	Monthly/Quarterly leak[f] detection and repair	7.7	(100)	240
	Monthly leak detection and repair	0.4	7	1,450
Pumps	Quarterly leak detection and repair	2.0	590	590
	Monthly leak detection[f] and repair	2.3	610	800
	Dual mechanical seals	2.6	4,900	31,000

[a] The control costs per VOC emission reduction are considered typical of control techniques for equipment leaks in gas processing plants and are used in selecting the level of control required by the standards.

[b] Further discussion of control techniques used can be found in Chapter 4.

[c] Emission reductions are for Model Plant B: 12 pressure relief valves, 6 compressor seals, 150 open-ended valves or lines, 6 liquid service and 6 gas service sampling connections, 750 valves, and 6 pump seals.

[d] Average dollars per megagram = (net annual cost of the control technique - emission reduction of the control technique).

[e] Incremental dollars per megagram = (net annual cost of the control technique - net annual cost of the next less restrictive control technique) (annual emission reduction of control technique - annual emission reduction of the next less restrictive control technique).

[f] Control techniques selected as basis for the final standards are underlined.

[g] Parentheses denote cost savings.

[h] Emission reduction and costs for compressors are from the BID for the proposed standards, Appendix H, Table 3. Costs based on half of all compressors requiring a dedicated control device.

[i] Costs and emission reduction for closed purge sampling represent both inlet gas sampling and product liquids sampling.

[j] These numbers are based on an average of the cost-effectiveness numbers for compressors with and without a control device (BID for proposed standard, Appendix G, Table 1).

Although monthly leak detection and repair provided greater emissions reduction (1.0 Mg/yr) than quarterly leak detection and repair (0.95 Mg/yr), and the average cost effectiveness was reasonable ($0/Mg), the incremental cost effectiveness was not reasonable. The incremental cost effectiveness of $5,800/Mg between monthly monitoring and quarterly monitoring indicates that, since 0.95 Mg/yr VOC emissions can be reduced with quarterly monitoring at an industry savings of $610/Mg, the remaining 0.05 Mg/yr attributable to monthly monitoring requires an industry expenditure of $5,800/Mg.

The EPA also considered the installation of upstream rupture disks as a regulatory alternative. Rupture disks would result in essentially 100 percent emissions reduction, or 1.5 Mg/yr for a typical plant. However, the average ($6,800/Mg) and incremental ($22,000/Mg) cost effectiveness values were not considered reasonable.

Based on all of these data, EPA selected quarterly leak detection and repair as the basis for the promulgated standards for pressure relief devices.

3.7 SAMPLING CONNECTIONS

The EPA considered a single regulatory alternative, closed purge sampling, to control VOC emissions during purging of sampling systems. However, examination of the costs and emissions reductions for closed purge sampling indicated that the cost effectiveness ($7,000/Mg) was unreasonable. Therefore, there are no requirements in the standards for sampling connections.

4.0 FORMAT AND REQUIREMENTS OF STANDARDS

4.1 FORMAT OF STANDARDS

Comment: One commenter (IV-D-12) stated that the approach taken by EPA in setting standards for various pieces of equipment to control VOC emissions is unnecessary, noting that in other industries EPA has allowed a bubble concept for the aggregation of total emissions from large facilities.

The commenter indicated that if EPA can demonstrate that total VOC emissions from a specific plant need to be controlled due to an ambient ozone violation in the area, the Agency should provide a total VOC emissions limit for the plant and let the plant determine the most appropriate means of meeting the emissions limit.

The commenter specifically suggested that EPA revise the proposed standards to set a total emission standard for a plant of approximately 150 pounds per day of VOC from valves and process equipment. In using this limit, the commenter stated that a plant operator could choose technology and operating procedures tailored for the specific plant design and could decide on necessary recordkeeping and maintenance scheduling as appropriate to meet the limit. The commenter believed that several other industries are regulated in this way under 40 CFR 60.

Response: A combination of equipment, work practice, design, and operational standards was selected as the format of the standards for process units and compressors (i.e., the affected facilities). Different formats are required for different types of leaking equipment because characteristics of the equipment, the available emission control techniques, and the applicability of the measurement method used for equipment leaks differ.

Setting a single emission limit for a given plant would be impracticable because the cost associated with measuring emissions from each potentially leaking piece of equipment would be unreasonable for most plants. In addition, the emissions limit (if one were set for the entire plant) would likely be nearly zero because most pieces of equipment do not leak. (The emissions from a few pieces of equipment that may leak averaged with emissions from the majority of equipment that may not leak would be close to zero.)

The EPA is developing a policy for approving NSPS bubbles on a case-by-case basis. This policy will be proposed in the Federal Register in the near future. Applications for NSPS bubbles will be considered in accordance with this policy.

4.2 VALVES

4.2.1 Difficult-to-Monitor Valves

Comment: One commenter (IV-D-30) stated that difficult-to-monitor valves can not be eliminated from new facilities, and recommended that difficult-to-monitor valves in new facilities be subject to the same annual inspection requirements as those in modified or reconstructed facilities. The commenter noted that block valves under relief valves, open-ended valves for testing of relief devices, and certain open-ended valves for purging equipment at start-up must be placed in high locations. Another commenter (IV-D-37) suggested that up to 10 percent of valves in general should be considered difficult to monitor and should be exempted from monitoring requirements except annual visual inspections.

Response: Upon reviewing the comments on the proposed standards, EPA accepts that eliminating all difficult-to-monitor valves from new facilities may substantially increase the costs of constructing new facilities, for example, due to the necessity for additional fixed ladders and platforms. Estimation of these additional costs is not possible due to the wide variability of factors such as the height of the valves and the ability to co-locate difficult-to-monitor valves.

Commenter IV-D-30 did not provide any data to indicate how many valves in new gas processing plants would be difficult to monitor. Although commenter IV-D-37 suggested that 10 percent of valves in general should be considered difficult to monitor, no basis for this number was given. The EPA expects the proportion of difficult-to-monitor valves in gas plants to be similar to that of refineries. A refinery maintenance study (Docket Item II-A-11) found that about 3 percent of over 8,000 total valves investigated could not be reached without extraordinary aids such as scaffolding or cherry pickers. Based on this study and on telephone conversations with refinery process design engineers (Docket Item IV-B-8), the Agency believes the 3 percent figure is accurate representation for gas plants. Therefore, the promulgated standards allow the owner or operator of a newly constructed facility to designate up to 3 percent of its valves as difficult to monitor. The standards require annual monitoring of these valves. Limiting the percentage of allowable valves that may be difficult to monitor provides the incentive to minimize the number of such valves in new units, while ensuring that an owner or operator would not incur unreasonable costs by attempting to eliminate all difficult-to-monitor valves in new units.

Comment: One commenter (II-D-10) noted difficulties in performing monitoring of valves located atop gas plant towers since they are not equipped with platforms. In addition, the commenter remarked that not all valves are accessible, and many valves cannot be reached or monitored in 1 minute. The commenter also noted that the economic analysis in the draft NAPCTAC BID did not consider relocation of components to eliminate "difficult-to-monitor" valves.

Response: Provisions for difficult-to-monitor valves have been added to the standards since this comment was written in May 1981. Less frequent monitoring (annual) for difficult-to-monitor valves was allowed for existing plants in the proposed standards, while annual monitoring for all difficult-to-monitor valves is being allowed in the final standards, since monitoring of these valves on a monthly basis is not cost effective. The EPA used 1 minute per valve as an average monitoring time based on actual process unit testing. Since the 1 minute value represents an average monitoring time for all valves, some valves may take longer, while others will take less time. The cost of monitoring valves is based on the 1-minute average; therefore, 1 minute is considered to be a reasonable monitoring time for all valves.

4.2.2 Alternative Standards

Comment: One commenter (IV-D-20) commended EPA for developing alternative standards for valves in VOC service. However, the commenter stated that 2.0 percent allowable leakers may not be an attainable standard. The commenter stated that his company operates several gas plants with less than 20 valves in VOC service, and that a leak in only one valve would therefore result in a violation. The commenter recommended that the standard be changed to 10 percent allowable leakers or at least one valve leaking over the inspection interval at each facility.

The commenter recommended that the second alternative standard for valves (skip-period monitoring) be retained except for changing the allowed 2 percent leakers to 10 percent.

Response: Alternative standards for valves have been provided in the standards because EPA judged that the emission reduction and the annual cost relationship is unreasonably high for process units that have fewer than 1.0 percent of valves leaking over an extended period. Due to the variability in valve leak detection, process units that average less than 1.0 percent of valves leaking will have, at times, more than 1.0 percent of valves leaking. Therefore, to provide for the variability in leak detection, EPA set the allowable percentage of valves leaking for any point in time at 2.0 percent. (A complete description of the methodology used to determine the allowable percentage of valves leaking is presented in Docket Item II-B-43.)

The allowable percentage of valves leaking applies to alternative standards for valves, hence, owners or operators are not required to meet a percentage of valves leaking unless they elect to do so. Also, under the skip monitoring alternative standards, if greater than 2.0 percent valves are detected leaking, a violation has not necessarily occurred. Owners or operators would simply be required to return to monthly/quarterly leak detection and repair. If, as the commenter claims, a gas plant has less than 20 valves in VOC service, the owner or operator may elect to follow an alternative standard for valves. However, one valve leaking would exceed the allowable percentage (2.0) of valves leaking. Since 20 valves would require very little time to monitor, alternative standards are really unnecessary. The EPA does not expect many gas plants processing more than 10 MMscfd with 20 valves or less.

Comment: One commenter (II-B-23) requested that a "reference leak detection program" be defined in Section 60.633-2 of the regulation.

Response: A "reference leak detection program" is simply the requirements for valves in Section 60.632-6, namely, a monthly/quarterly leak detection and repair program. The required standards serve as the basis for the skip period leak detection and repair alternative standards. After an owner or operator has demonstrated that he can maintain a performance level of 2 percent or less for either 2 or 5 consecutive quarters using the required standards as the "reference leak detection program," then the owner or operator can reduce the monitoring frequency to either every 6 months or once a year. The EPA does not consider it necessary to add a definition for "reference leak detection program" when the requirements are specified in Section 60.632-6 of the proposed standards, which have not changed since proposal.

4.3 PUMPS

4.3.1 Barrier Fluid Requirements

Comment: One commenter (IV-D-35) wrote that the requirements of Section 60.632-2(d)(2) were unclear. The commenter asked if the barrier fluid must be a non-VOC or a heavy liquid. The commenter indicated that Section 60.632-3(d) was similarly unclear.

Response: If a seal system is used, the barrier fluid must be either a non-VOC or a heavy liquid. This applies to seal systems for both pumps in light liquid service and compressors. In both back-to-back and tandem seal arrangements, a non-VOC or heavy liquid barrier fluid is required because the barrier fluid could leak across the secondary seal and release VOC to atmosphere. If a VOC barrier fluid were used instead, the dual seal would effectively be only a single seal in terms of sealing VOC from the atmosphere. Heavy liquid barrier fluids would include heavy final products, heavy oils, water, etc.

4.3.2 Dual Mechanical Seals

Comment: One commenter (IV-D-15) requested that pumps designed with dual mechanical seals with or without barrier fluid systems be exempted from monitoring requirements. The commenter noted that dual seals have been used for many years, primarily for safety and operational reasons. Upon failure of the inner seal, an alarm is activated and the pump then operates on the outer seal for a short time until a standby pump is placed in service or the pump can be otherwise shut down for seal repair. The commenter proposed annual certification by the operator that pumps are so equipped, that the visual inspection requirements of Section 60.632-2 are met, and that the repair requirements of Section 60.632-2(d)(6) (iii) are met.

Response: Pumps with dual mechanical seals that have non-VOC or heavy liquid barrier fluid systems are exempt from routine monitoring, provided that pumps are visually inspected on a weekly basis, as prescribed by Section 60.632-2(d) of the proposed standards. The EPA considers dual mechanical seals with barrier fluid systems to be 100 percent effective in reducing pump seal emissions when designed and operated properly. Mechanical seals, either single or dual, can leak and normally utilize either the process fluid or the barrier fluid leakthrough to complete the seal. Since dual mechanical seals without barrier fluid systems may develop leaks, routine leak detection and repair is required.

4.3.3 Weekly Inspections

Comment: One commenter (II-D-10) stated that EPA provides no support for the arbitrary selection of the weekly visual inspection of pumps.

Response: Visual inspection of pumps is necessary to check for liquids dripping from the seal. As the seal wears over time, VOC leakage is likely to increase, so it is important to monitor pumps on a regular basis. As stated in Table 8-3 of the BID for the proposed standards, weekly visual inspections would take about one-half minute per pump or about 10 minutes per week (9 hours per year) for one person at a large plant with about 20 pumps. The annual cost of these visual inspections would be about $160 (June 1980 dollars). The cost of weekly visual inspection is reasonable. The EPA has concluded that this situation is not likely to occur.

4.4 COMPRESSORS

Comment: Several commenters (II-B-23; II-D-10; II-D-30; IV-D-13; IV-D-15; IV-D-19; IV-D-21; IV-D-23; IV-D-24; IV-D-26; IV-D-27; IV-D-29; IV-D-30; IV-D-31; IV-D-35; IV-D-33; IV-D-34; IV-D-36; IV-F-1a; IV-F-1c; IV-F-1e) expressed concerns about potential safety hazards associated with the installation of closed vent systems on reciprocating compressors.

The commenters stated that compressors must be equipped with foolproof systems to prevent pressurizing the distance piece and must absolutely prevent the intrusion of air and backpressure from the flare header. Additionally, flow of the compressed gas into the compressor driver crankcase must be prevented.

Other commenters stated that, where existing control devices do exist, they are often used to control sour gas. Since the gas-contacting surfaces of the compressors are not metallurgically compatible with sour gas, tie-in to the existing control device would not be possible due to potential corrosion problems.

Similarly, other commenters (IV-D-33; IV-D-36) said their experience shows the only times they would consider it a safe practice of tying a distance piece into a closed vent system to a control device is when a low pressure flare system is available.

The commenter further noted that some gas plants use flare systems solely for high pressure process vessel relief, such as straddle type plants, plants processing naturally occurring high pressure field gas, or plants where compression is done in the field prior to plant processing. The commenter stated that their experience shows that a check valve is not sufficient to prevent backpressure on the flare header from pressurizing the distance piece. The commenter recommended, at the very least, that the requirement for tying the distance piece into a closed vent system be evaluated on a case-by-case basis. In addition, the commenter had no objection from a safety viewpoint to tying the packing vent into a closed vent system and maintained that the majority of compressor VOC emissions would be controlled with just the packing vents tied to a closed vent system. The commenter cited a letter (Docket No. II-D-44) previously submitted that supports their safety concern for pressurizing single distance pieces.

Another commenter (II-D-10) stated that tying seal emissions back into the compressor inlet was not viable because of pressure considerations.

All of these commenters recommended that EPA exempt reciprocating compressors from the standards.

Response: The commenters' primary concerns are pressurization of the compressor distance piece and flow of the compressed product into the driver crankcase. The EPA cost analysis was based on equipping the compressors with two-compartment distance pieces, which are designed to collect hazardous or toxic gases. The two-compartment distance pieces allow for the compressor side compartment to be sealed and vented to a control device, while the crankcase side compartment may remain open to the atmosphere. By allowing the crankcase side to remain open, the "break" between the compressor and the driver crankcase is maintained, preventing the flow of compressed gases into the crankcase. Double distance pieces have been recognized by the industry as a safe method of seal gas collection for at least 10 years, as evidenced by the 1974 API Reciprocating Compressor Standard.[1]

Given that the flow of gas into the compressor crankcase may be prevented using double distance pieces, the remaining concern of the commenters was that the distance pieces might become pressurized from the flare header or develop explosive atmospheres due to air intrusion.

In order to ensure that the distance pieces did not become overpressurized, EPA recommended several safety features, as follows:

- Distance pieces should be routed to the flare through a separate flare line, and not the plant's main flare header. The EPA included the cost of 100 meters (300 feet) of 2-inch pipe for this purpose.
- Each distance piece would be equipped with a check valve to prevent backflow, and the flare line would be equipped with a low-burst pressure rupture disk to relieve any catastrophic failures.
- The system should be pressurized. A water-sealed trap was included in the flare line to prevent air intrusion.

Although no system can be made entirely failsafe, EPA has estimated the costs for a control system for compressors which, although simple in design, was designed with safety as the primary consideration.

Several commenters indicated that, where existing flares were in sour gas service or high-pressure service, a dedicated control device could be required for the compressor vent control system. The EPA recognized at proposal that, in many cases, gas plants would not have a control device present, and exempted wet gas reciprocating compressors in plants where a control device was not already present. However, based on the comments received since proposal, and the unreasonable cost effectiveness of wet gas reciprocating compressor controls used at more plants than EPA estimated at proposal, EPA has decided to exempt all wet gas reciprocating compressors from the promulgated standards (see Section 7.2). However, since installation of a control device is cost effective for wet gas centrifugal compressors and all compressors in natural gas liquids service, control of these compressors is still required by the promulgated standards (Docket Item IV-B-7).

---

[1] API Standard 618, 2nd Edition, July 1974. Docket Item No. II-I-35.

Numerous control techniques are available for compressor seal emissions. Some plants may not be able to pipe emissions into a compressor inlet, as noted by the commenter. The EPA also recognizes that some plants do not have suitable flares available, as use of a high pressure flare would require an auxillary compressor. Hence, EPA included the cost of a suitable low pressure flare, which would not require an auxillary compressor, in the cost analysis presented in the BID for the proposed standards (Appendix G).

Comment: One commenter (IV-F-1a) stated that compressors should be exempt from the standards because the control of emissions from them requires the greatest capital investments while providing the lowest cost effectiveness.

Similarly, another commenter (IV-D-24) noted that Table 3-2 of the BID for the proposed standards shows that compressors represent only 2 percent of the EPA's total estimated VOC leakage. He concluded that the increased risk and cost of controlling compressor emissions is not justified.

Response: Compressor emissions, as shown in the BID for the proposed standards, Appendix H, are 15.8 percent of all gas plant emissions. When examining the selection of best demonstrated technology (BDT) considering costs for the standards, EPA compared available demonstrated controls for each type of source. For compressor seals, closed vent and seal systems were considered as the only available demonstrated technology. Since the use of closed vent and seal systems can be accomplished at reasonable cost and cost effectiveness, the controls are required. The EPA does, however, consider the costs of controlling reciprocating compressors in wet gas service to be unreasonable and has exempted those compressors from the promulgated standards.

4.5 OPEN-ENDED LINES

Comment: Two commenters (IV-D-15 and IV-D-24) opposed the requirements in Section 60.632-5 to plug open-ended valves or lines because they present a potential safety hazard. The open end is frequently some distance downstream from the valve, and there could be significant safety hazards if the operator fails to remove the covering prior to opening the drain valve or purging valve. One commenter (IV-D-15) said there was a need to include an alternative standard for frequently used valves, such as to sample the outlet quarterly. One commenter (IV-D-24) questioned the accessibility of the open ends noting that a vent line may be on a riser pipe well above the work area or a drain line may dump into a sump tank. He further questioned the benefit of the open-ended line requirements because many lines must be routinely opened to vent, purge, sample or drain some system, and any fugitive emissions would be released at that time.

In contrast, one commenter (IV-D-20) agreed with the use of caps, plugs, and second valves to control leakage from open-ended lines. The commenter stated that the practice was already being done in his company's gas plants.

Response: The standards for open-ended valves or lines provide operators the flexibility to add either a cap, blind flange, plug, or a second valve, depending upon the individual application. The EPA acknowledges that plugging open-ended valves or lines may present a potential safety hazard in certain situations. Accordingly, if a second valve is used, the standards require that the upstream valve be closed before closing the downstream valve. This operational requirement is merely sound practice that plant operators currently follow to prevent process fluid from being trapped between the valves. If hot (or cold) product is trapped between the two valves, as it contracts (expands) from cooling (heating) to ambient temperature, it could cause the pipe, the valve stem, or the valve seat to fail. Should the inner valve leak through the valve seat, however, the product will eventually fill the piping between the valves with ambient temperature fluid without stressing the valve seat.

The standards provide sufficient flexibility for the operator's concern with plugging frequently used valves. Adding a second valve avoids the risk of premature failure of pipe connections caused by the frequent removal of a cap or plug.

Leak detection and repair for the control of VOC emissions from open-ended valves or lines is inappropriate because it would achieve less emission reduction and may cost more to implement than the equipment and operational standards for open-ended valves because of repeated inspections of nonleaking sources.

Comment: One commenter (II-D-10) questioned EPA's recommendation to use teflon tape to seal threaded connections. The commenter noted that teflon tape works well for small sizes (2-inch nominal diameter and smaller); however, the sealing ability on larger sizes has not proved satisfactory.

Response: Joints larger than 2 inches in diameter are usually either flanged or welded, and not threaded. The EPA's point discussed in the BID for the proposed standards is reiterated by the commenter, namely, that leaks from small threaded connections can be reduced by using teflon tape on the threads before the connection is made. The EPA makes no claim that the tape is effective on larger connections.

Most open-ended lines subject to the standards would be 2 inches or smaller in diameter. These lines could be sealed with teflon tape on the appropriate cap or plug. Although the standards would require the closure of larger open-ended lines, which would require more costly control, the cost of plugging open-ended lines is based on the addition of a second valve instead of a cap or plug. In most cases, small open-ended lines can be capped or plugged at significantly lower cost than with the second valve assumed by EPA. Large blind flanges cost about the same as small valves and, therefore, are reasonable.

4.6 PRESSURE RELIEF DEVICES

4.6.1 Annual Certification

Comment: One commenter (IV-D-15) offered an alternative method of achieving at least equivalent emission control of pressure relief devices because he thought the testing, reporting, and recordkeeping of the hundreds of relief valves that would typically be installed in a new plant would be an immense burden. Also, the additional investment to tie all relief valves into a closed system to gain exemption from monitoring would be large. The commenter preferred to follow certain design criteria and test practices to verify relief set pressures. The commenter proposed that an operator annually certify that these conditions are met. The commenter also stated that relief valves should be exempt when burst-heads and test inserts are installed. The commenter further wrote that if such installations are made for operator design considerations, then control effectiveness should be acknowledged, and the relief valve should be exempt from monitoring, compliance testing, and reporting.

Response: The EPA considered alternative control techniques, including rupture disk (burst-heat) installations, leak detection and repair, and no control (baseline) for pressure relief devices prior to proposing the standards. The routine leak detection and repair requirements selected for inclusion in the proposed standards were estimated (BID for proposed standards, page H-4) to reduce VOC emissions from relief devices by 0.076 Mg/yr per valve, with a savings to industry of $46/device-year. As such, the quarterly leak detection and repair program required by the standards will result in a savings to industry while reducing VOC emissions.

The commenter offered an alternative control technique for relief devices based on verification of set pressure and certain relief device design criteria, apparently based on the assumption that relief device leaks are the result of valve openings during operation. However, most relief device leaks are from "closed" valves and are the result of corrosion and/or improper reseating after a pressure release. As such, set-pressure verification would not ensure that a pressure relief device would not leak. The standards, therefore, remain unchanged.

The commenter also requested a blanket exclusion for relief devices equipped with rupture disks and test inserts. The EPA considers rupture disk systems to be effective control devices for emissions from pressure relief devices. Relief devices equipped with rupture disks may be designated for "no detectable emissions" and require only an initial acceptance test and annual compliance tests to ensure proper installation and operation. Since rupture disks may burst or develop leaks through corrosion, annual performance tests, as well as rapid (5-day) replacement after they burst, are necessary; therefore, the standards remain unchanged.

4.6.2 Rupture Disks

Comment: One commenter (IV-D-20) stated that control of VOC emissions from pressure relief devices by installation of a rupture disk upstream or downstream creates potential safety problems. Furthermore, the commenter claimed that pressure relief devices are already checked and maintained in as leak-free condition as possible since leaks would result in the loss of valuable hydrocarbon products.

Response: The standards for pressure relief devices are based on quarterly leak detection and repair; however, the standards allow operators to use control techniques that achieve emission reductions equivalent to quarterly leak detection and repair. The EPA has determined that pressure relief devices that comply with the "no detectable emissions" limit and pressure relief devices that are controlled through a closed vent system to a control device would achieve equivalent emission reductions.

Rupture disks eliminate equipment leaks of VOC through the relief device unless an overpressure occurs. After an overpressure release, replacement of the rupture disk once again eliminates equipment leaks. Pressure relief devices are required to operate with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and are required to return to this condition within 5 days following a pressure release.

While it is possible that operators would not use rupture disks because of safety concerns, rupture disks are allowed in the standards and they are presently used in gas plants. If a rupture disk is used, a pressure sensor could be installed to warn operators if a pressure increase has occurred between the disk and relief valve.

4.6.3 Accessibility Rechecks

Comment: Several commenters (IV-D-19, IV-D-21, IV-D-23, IV-D-26, IV-D-30, IV-D-36, and IV-F-4) requested that EPA revise the monitoring requirements for pressure relief devices. The commenters stated that relief devices cannot be placed in accessible locations for safety reasons. Commenters (IV-D-23 and IV-D-30) contended that elevating relief valves (i.e., atop towers and columns) provides for better atmospheric dispersion of any released hydrocarbons to minimize explosion hazards. Therefore, relief devices are accessible only by adding ladders and platforms or by crane, and these costs were not included in considering the economic costs of this rule. One commenter (IV-D-30) also pointed out that elevated relief valves will have fewer emissions than relief valves at lower locations in equipment processing both gas and liquid phases because a smaller mass of gas would be released to provide the same pressure drop.

One commenter (IV-D-23) thought that there was no benefit to the requirement that pressure relief devices be monitored within 5 days of relieving because leaking pressure relief valves cannot be repaired until the unit is shutdown. Also, at an unmanned or partially manned plant, a relief valve could relieve without anyone's knowledge. Other commenters (IV-D-36 and IV-D-26) suggested retesting relief valves after overpressures at the next scheduled monitoring of valves and pumps. These commenters pointed out that many facilities will be utilizing contract services to handle their leak detection and repair, and a special trip (costing in excess of $1,000) would be required to recheck a pressure relief device after an overpressure. Another commenter (IV-F-4) requested that EPA allow a 14-day period for retesting of relief devices after overpressures. One commenter (IV-D-21) added that inspection of pressure relief valves following each pressure release is difficult to arrange since the economics of small to mid-size plants will not allow either the necessary instruments or the instrument technicians to be available at all times.

One commenter (IV-D-19) recommended monitoring pressure relief devices 1 week after each pressure relief and disregard quarterly monitoring because relief devices will leak within the first week after relieving, or not at all. This commenter argued that quarterly monitoring would be an unnecessary duplication of effort. Another commenter (IV-D-30) suggested that relief valves be subject to annual leak detection and repair as are difficult-to-monitor valves.

Response: As presented in the background information document for the proposed standards, emissions from pressure relief devices in natural gas plants can be reduced by 0.076 Mg/year per pressure relief device by implementing quarterly leak detection and repair. This emission reduction value, which was based on emission measurements at gas processing plants, resulted in the product savings ($73/device-year) being almost triple the costs ($27/device-year) of monitoring. The statement made by commenter IV-D-30 is not relevant since the elevation of a pressure relief device for gas phase service does not affect the amount of gas released. An elevated relief device in liquid phase service would affect the mass of emissions. However, very few, if any, pressure relief devices at gas plants would be in liquid service, and the standards apply only to gas service relief devices. The EPA based the emission factor for pressure relief devices on gas phase releases only because few relief devices are used in liquid phase service.

Commenter IV-D-19 is incorrect in stating that relief devices will leak within 1 week or not at all. While it may be true that significant leakage due to improper seating or unseating of the relief valve occurs relatively soon after a release, minor leaks may develop over longer periods due to corrosion or valve "chatter". Since safety regulations already require most pressure relief devices to be inspected annually, EPA requires only three additional inspections per year. Pressure relief devices could be monitored at each quarterly inspection using the same equipment that is used during the current annual inspections. Quarterly inspections could improve plant safety through both leak detection and detection of closed block valves.

One commenter contended that relief valves cannot be repaired without a shutdown. While this is true in some cases, most relief valves are equipped with upstream block valves to allow testing or replacement of the relief valve while the unit is in operation. These relief valves may be repaired with the unit in operation.

Several commenters expressed concern about performing rechecks on pressure relief devices within 5 days of a pressure release, since monitoring personnel and instruments may not be available. The EPA recognizes that many small plants will use contractors or central office personnel to perform routine monitoring and that in these cases the monitoring team is not available except during scheduled test periods. In these situations, EPA believes that the cost of obtaining the monitoring services for a single relief valve would be unreasonably high. Therefore, the final standards allow small plants that are not monitored by on-site personnel to delay rechecks up to 30 days after a pressure release.

Comment: One commenter (II-D-10) questioned the benefit of monitoring safety valves/rupture disks considering the inherent danger in monitoring them. In support of his concern, the commenter added that a person who is monitoring when a high pressure release occurs could be injured or killed, particularly if the person is holding onto a ladder near the top of the vessel and is handling all the paraphernalia required for monitoring. The commenter noted that gas plants normally have relief valves and/or rupture disks installed on top of vessels or columns without access platforms.

Response: The standards for gas service pressure relief devices in natural gas processing plants are work practices consisting of a quarterly leak detection and repair program. The pressure relief devices are also required to be monitored within 5 days after each overpressure to determine if a leak has occurred as a result of the overpressure. Monitoring of these devices should be performed by personnel who understand the precautions and practices recommended by industry and ASME codes. If a pressure relief device is likely to relieve when monitoring occurs, then special precautions, such as monitoring of process conditions (temperature and pressures), should be taken by the owner or operator. Based on EPA's experience in collecting data for pressure relief devices, these devices can be monitored safely. As mentioned earlier, most plants already perform annual relief valve tests, further indicating that monitoring can be performed safely.

Comment: One commenter (II-D-10) stated that EPA's requirement for capping all open-ended lines suggests capping relief valve discharge lines that must remain open to provide a path for discharging the fluids from the valve in case of an emergency. Another commenter (IV-D-34) requested that a new paragraph be added to the standards for open-ended valves or lines:

> (c) Open-ended valves which serve as automatic or manually actuated emergency shutdown systems for gas processing plants are exempt from the provisions of the section and shall comply with the provisions of §60.632-6.

The commenter noted that emergency shutdown (ESD) systems are required to protect people and equipment. ESD systems dump gas to atmosphere by automatic or manual actuation through a series of open-ended valves. The commenter maintained that as a safer alternative open-ended valves or lines in ESD systems should be subject to the valve standards rather than to the open-ended valve or line provisions of Section 60.632-5 of the proposed standards. The commenter added that leakage in a pressured ESD system is self-monitoring, since a drop in system pressure actuates the ESD system.

Response: As stated in the definition of "open-ended line" (Section 60.631 of the proposed standards), open-ended lines do not include pressure relief valves. Relief valve discharge lines are exempt from the capping requirement because relief valve horns must always remain open for the relief valve to function. Assuming ESD systems are relief valves, they would be exempt from the standards for open-ended lines because they are excluded from the definition of open-ended lines.

4.7 CONTROL DEVICES

4.7.1 Efficiency Requirements

Comment: One commenter (II-B-23) stated that vapor recovery compressors are more representative of gas plant applications than condensers or absorbers and should be the appropriate standard for gas plants.

Response: Control devices are not limited to flares, incinerators, condensers, or absorbers. They are given as examples of acceptable systems. Control devices must have a VOC control efficiency of at least 95 percent. If a recovery compressor were designed and operated with greater than 95 percent reduction efficiency, it would be an acceptable control device for natural gas processing plants.

Comment: Several commenters (II-B-23, IV-D-10, IV-D-13, IV-D-15, IV-D-20, IV-D-24, IV-D-31, IV-D-33, IV-D-35, IV-F-1c, IV-F-1e) took issue with the velocity and heat content limits for flares, and requested they be deleted from the standards. Many of these commenters maintained that existing emergency flares are capable of greater than 98 percent combustion efficiency if properly operated.

Some of the commenters specifically questioned limiting heat content values provided by the standards. One commenter (IV-D-33) stated that gases with heat contents of about 5.6 MJ/scm (150 Btu/scf) could be flared successfully, while others (IV-D-24 and IV-D-35) noted that produced (field) gas often has low heat values due to N_2 and CO_2 entrainment, especially in the latter stages of enhanced recovery.

Several commenters indicated that studies available to EPA showed that flares operating over a wide range of gas heat content values and flare exit velocities have destruction efficiencies in excess of 98 percent. One of the commenters (IV-D-10) maintained that EPA based the flare exit velocity limit on test data used for the SOCMI NSPS, with the testing limited to velocities of less than 18.3 m/sec (60 ft/sec). The commenter did not agree with EPA's conclusion from these data that higher velocities would result in lower efficiencies, stating that EPA should require that flame stability be maintained rather than limiting the heating value and velocity of the gas stream. Many commenters

(IV-D-21, IV-D-23, IV-D-26, IV-D-33, IV-D-36, IV-F-1a) were concerned that API Recommended Practice (RP) 521 was ignored, noting that RP 521 recommends a flare tip velocity of 0.2 Mach for continuous flaring and 0.5 Mach for short-term flaring for sizing the flare. Several commenters indicated that to design a flare for maximum exit velocities of 18.3 m/sec (60 ft/sec) under emergency conditions would result in very large flare tips, increasing the chance of air migration and stack explosions during normal operation.

Four commenters (II-B-23, IV-D-27, IV-D-29, IV-D-35) favored a 20 percent opacity level (except for 5 minutes in any 2 consecutive hours) and contended that the "no visible emissions" requirement was too stringent.

Response: As noted above, EPA selected control devices that achieve at least 95 percent reduction efficiency as the "best demonstrated technology" (BDT) for control devices used in complying with the standards. In reflecting this selection of BDT, EPA proposed specific design and operational requirements to ensure that flares used to comply with the standards achieve at least 95 percent reduction efficiency. The proposed design and operational requirements were, in EPA's judgment, the only set of limits that ensure at least 95 percent reduction efficiency. The EPA considered setting requirements that better reflect 95 percent reduction efficiency but rejected this because data do not support setting design and operational requirements that would distinguish between 95 and 98 percent reduction efficiency. The EPA agrees with the commenters who stated that existing flares in this industry are capable of greater than 98 percent reduction efficiency if properly operated. However, the only way EPA knows to ensure this judgment is to set limits on design and operation of the flares that reflect BDT.

Since proposal, EPA further examined previously available and new flare studies cited by the commenters (Palmer (1972); Siegel (1980); Lee and Whipple (1981); Howes (1981); McDaniel (1983)), and concluded that flares with exit velocities up to 122 m/sec (400 ft/sec) can achieve 98 percent destruction efficiency, as suggested by one commenter, if the gas heat content is sufficiently high. Therefore, the final standards provide an additional equation for determining velocities up to 122 m/sec (400 ft/sec) depending on the gas heat content, as follows:

$$\mathrm{Log}_{10}\,(V_{max}) = (H_T + 28.8)/31.7$$

where V_{max} = maximum permitted velocity, m/sec
and H_T = the net heating value of the gas, MJ/scm

This equation was based on flare efficiency data available to EPA, primarily from a study conducted by Energy and Environmental Research Corporation, entitled "Evaluation of the Efficiency of Industrial Flares-Test Results," " Pohl, et. al. (1984), Docket Item IV-A-1. This equation will allow streams with net heating values greater than 11.2 MJ/scm (300 Btu/scf) to be flared at higher velocities, while ensuring an effective reduction efficiency that reflects BDT. These limits do not allow flares to be used that burn streams with a net heating value of 5.6 MJ/ scm (150 Btu/scf), as suggested by one of the commenters. In EPA's judgment, flares burning streams with this net heating value can not be considered to be effective control devices. The available data do not support revising the lower net heating value limit (i.e., 300 Btu/scf).

An underlying concern of the commenters appears to result from a misunderstanding that flares must never exceed the maximum permitted velocity (e.g., an 18 m/sec (60 ft/sec) tip velocity) for steam-assisted and nonassisted flares. As can be determined by reviewing 40 CFR 60.8, emergency releases to the flare are not considered normal operation and, therefore, the velocity limits do not apply in such circumstances. The specifications described in API RP 521 ("...a velocity of up to 0.5 Mach for a peak, short-term, infrequent flow...") are intended to be used in emergency situations, whereas the maximum velocity requirements for flares specified in the EPA standards are intended to be used during normal flare operation.

With respect to the "no visible emissions" limit placed on flares, EPA considers a requirement for no visible emissions, with the exception of 5 minutes in any 2-hour period, to be reasonable. Smokeless flares have been regulated in States with limits similar to the proposed opacity limits. The commenters offered no appropriate basis for changing the limits to another level. In addition, most streams in natural gas processing plants are highly volatile gases or light liquids, and are readily burned in smokeless flares. Some commenters indicated that continuous smokeless operation would require either automatic or manual control of the flare on a continuous basis. However, EPA believes that if this type of control is needed to ensure the use of BDT, it is reasonable, and that most gas plants would have little difficulty in obtaining smokeless combustion.

Comment: One commenter (IV-D-31) thought that the establishment of operating criteria is not permissible under Section 111 of the Clean Air Act. Section 111 specifically precludes the Administrator from adopting design or work practice requirements unless it is not feasible to prescribe or enforce a performance standard. According to the commenter, a performance standard is readily available in the case of controlling VOC emissions by combustion and is included in the proposed standards, namely, an opacity limit.

Response: As indicated by the commenter, the "no visible emissions" requirement for flares does constitute a performance type standard. However, this portion of the flare requirements only partially reflects BDT. All of the requirements as promulgated are needed to reflect BDT. Since unburned hydrocarbons can be colorless and can be emitted without being visible, the opacity requirement does not provide a complete measure of VOC destruction efficiency. The EPA could set a performance standard at a specific destruction efficiency level. However, available data indicate that, unless flares are operated within the velocity and heating value requirements of the standards, they would likely not meet performance specifications. More importantly, performance testing for flares is extremely complex and costly, so that a standard requiring demonstration of a given efficiency level is, in fact, not practicable.

Comment: One commenter (IV-D-24) claimed that the proposed standards will force extensive design changes to existing flare systems at a cost that would adversely affect the economics of modification projects. The commenter stated that his company did not have any gas plants equipped with flares that meet the provisions of Section 60.632-9 of the proposed standards.

Response: If an existing flare does not achieve the required limits of the promulgated standards, then EPA would not recommend using the flare as a control device because such a flare is not likely to be effective in burning VOC emissions. However, flares are not the only control devices suitable for use in controlling gas plant emissions. The EPA believes that, in most cases, existing flares will meet the requirements of the standards where installed. In addition, the velocity limits for flares have been expanded (allowing more flares to comply with the standards) and are not required to be maintained during emergency releases.

For plants that do not have suitable flares, EPA has determined that it is cost effective to install a new flare solely for VOC control purposes if the plant decides that another control device is not available (Docket Item IV-B-7).

Comment: One commenter (IV-D-33) noted that API Publication 931, Chapter 14, states that residence times of 0.2 to 0.7 seconds at 1150 to 1400°F are sufficient to obtain satisfactory combustion and decomposition in most applications. The commenters' experience confirms the API parameters as sufficient to incinerate waste gases. The commenter favored deletion of the residence time and temperature requirements from the standards in favor of a 95 percent efficiency requirement.

Another commenter (IV-D-15) recognized that the residence time and temperature parameters were provided in the standards as alternatives to demonstration of 95 percent control efficiency, but was concerned that the parameters could be treated as requirements for some new processes where they would not be necessary for 95 percent destruction efficiency. The commenter also noted that the control device requirements should only apply during normal design conditions.

Response: As correctly noted by commenter IV-D-15, the temperature and residence time specifications presented in the standards were provided to allow demonstration of 95 percent efficiency through accepted design parameters rather than emissions testing. Incineration systems based on other design parameters may be used subject to demonstration of control efficiency by source emissions testing or suitable engineering calculations. Although the EPA parameters of 0.75 seconds and 816°C (1500°F) are somewhat higher than those stated in API Publication 931, the EPA parameters are based on known 95 percent destruction efficiencies for all cases, rather than "most applications" so that the use of the EPA parameters can be accepted as proof of 95 percent efficiency. The EPA realizes that, in some cases, shorter residence times and/or lower temperatures can provide 95 percent efficiency. An owner/operator, therefore, can provide design information such as emission rates and gas stream component analyses, and incinerator design specifications, for approval as an acceptable control device.

4.7.2 Flares

Comment: Commenters IV-F-1a; IV-D-29; and IV-D-23 stated that most companies will not include a smokeless flare in their new plant designs. Commenters IV-F-1a and IV-D-23 also noted, however, that in plants that have a flare system, the flare design would not adequately accommodate the seal leakage and/or would not meet the requirements of the proposed standards.

Response: Flares are one of several VOC control devices that might be used to comply with the standards. Flares are not required under the standards, but they are included because they can be used to reduce emissions of VOC at conditions that reflect BDT. Flares operated in accordance with the operating conditions provided in the regulation are acceptable alternatives to other control devices used to comply with the standards. Although EPA allowed for plants that did not include flares as a part of their initial design in setting the compressor standards, many plants are expected to include flares because gas plants are major sources of VOC; and in selecting best available control technology (BACT) and lowest achievable emissions reduction (LAER), smokeless flares are likely alternatives for the control of VOC emissions from emergency venting.

Comment: One commenter (IV-F-1c) indicated that the cost of equipment to monitor flare pilot lights is high, and the equipment is unreliable. Another commenter (IV-F-1e) noted that EPA provided no cost estimates for flare monitoring equipment.

Response: The presence of a flare pilot may be monitored with a thermocouple and appropriate transmitter. Contrary to the commenter's suggestion, thermocouples are highly reliable and are used throughout the petroleum industry.

The costs associated with the flare requirements are discussed in Chapter 7.

4.7.3 Continuous Operation

Comment: Two commenters (IV-D-15 and IV-D-20) questioned the requirement in Section 60.632-9(d)(g) of the proposed standards for full-time operation of vent systems and control devices. The commenters wrote that the operation of vent systems and control devices should not apply during shutdown and start-up operations. One commenter (IV-D-20) argued this is necessary because during such times the gas composition may be highly variable. Consequently, it would be difficult to design a flare to handle such a wide range of flows and compositions.

Another commenter (IV-D-15) requested that the requirements for a continuous burning pilot in Section 60.632-9(d)(2), include "... or an acceptable reignition device." The commenter stated that automatic ignition devices should be allowed as an alternative to monitoring the presence of a flare pilot. Other commenters (IV-D-29, IV-F-1a) stated that the fuel wasted to keep the flare burning would cost more than could ever be saved from implementing the standards.

Response: Start-up and shutdown operations are described in the General Provisions. Section 60.8(c) states that "Operations during periods of start-up, shutdown, and malfunctions shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of start-up, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard."

The EPA concurs that there is no basis for operating the flare when no leakage is emitted. The proposed standards (Section 60.632-9(g)) required closed-vent systems and control devices (including flares) to be operated at all times *when emissions are vented to these devices*. Therefore, the commenter's suggestion is not necessary. This provision will allow the use of a flare header flow detector and automatic ignition system to prevent waste of pilot fuel. However, when a flare is operating, the pilot light must be burning at all times to ensure the destruction of VOC emissions that may be released.

4.8 LEAK DETECTION AND REPAIR

4.8.1 Monitoring Frequency

Comment: Several commenters (II-B-23; IV-F-1c;IV-F-1e; IV-D-14; IV-D-15; IV-D-19; IV-D-27) stated that monthly monitoring of valves in light liquid and gas/vapor service is too frequent.

Three of the commenters (IV-F-1e; IV-D-14; IV-D-15) urged EPA to adopt quarterly monitoring for valve leaks, indicating that the small additional emissions decrease does not justify increased cost for monthly monitoring. Another (IV-D-24) urged EPA to adopt quarterly monitoring at most, yet recommend annual monitoring due to the mammoth paperwork burden the standards create.

One commenter (II-B-23) requested that EPA present an evaluation of more extended inspection frequencies as supported by the API-Rockwell study. Another commenter (IV-F-1c) requested that the monitoring period for valves be changed to annual, stating that the cost effectiveness of monthly monitoring is questionable due to the large number of valves and the manhours involved, while still other commenters (IV-D-13 and IV-D-23) said that, even though the standards allow quarterly monitoring, the initial frequency should be reduced to (IV-D-23) noted that it will not always be possible to reach facilities in North Dakota for monthly monitoring, whereas quarterly testing could be scheduled around the weather. In addition, quarterly monitoring would reduce yearly travel expenses by two-thirds; in North Dakota this is a $16,000-per-year savings.

Response: As stated in the preamble to the proposed standards, EPA considered monthly, monthly/quarterly, and quarterly monitoring intervals for valves. Each of these alternatives was compared in terms of the emission reduction achievable and the cost effectiveness of the leak detection and repair programs. At proposal, the standards were based on monthly monitoring because it provided the greatest emission reduction at reasonable costs.

The EPA recognized, however, that some valves have lower leak occurrence rates than others. Monthly monitoring of valves that do not leak for 2 consecutive months was judged to be unreasonable when compared to the additional emission reduction achieved by monthly monitoring over quarterly monitoring. Therefore, EPA proposed to allow a monthly/quarterly implementation program, whereby valves that do not leak for 2 successive months may be monitored quarterly until a leak is found. Also, under one of the alternative standards for valves, an owner or operator can skip from the monthly/quarterly program to less frequent leak detection (semiannually or annually) if a performance test level of 2.0 percent is achieved on a continuous basis (for either 2 or 5 consecutive quarters). The EPA expects that most gas plants would implement a monthly/quarterly leak detection and repair program for valves. In addition, the incremental cost effectiveness between monthly/quarterly and quarterly leak detection and repair is reasonable (see Table 3-1). Therefore, the standards still allow a monthly/quarterly program for valves, which has not changed since proposal.

One of the commenters suggested that valves be monitored quarterly from the onset of the program due to the remoteness of gas plants. As shown in the BID for the proposed standards, Appendix G, EPA carefully analyzed the cost effectiveness of monitoring small remote plants using central office or contract personnel. These analyses for small plants indicated that, for plants smaller than 10 MMscfd, monthly monitoring was not cost effective.

Comment: One commenter (II-B-23) questioned the validity of the leak detection and repair (LDAR) model upon which the economics of controlling emissions from valves and pump seals is based. The commenter asserted that the model was not developed using any gas plant data based on information presented in the AID (Docket Item II-A-25), Table 4-10.

Another commenter (IV-D-19) wrote that EPA's use of the leak occurrence rate function in the LDAR model is faulty. The commenter disagreed with the use of the 1.3 percent per month leak occurrence rate based on limited tests in chemical plants. The commenter noted that his company's refinery experience indicates a leak occurrence rate of 0.3 percent leakers per month. The commenter acknowledged that gas plant valves may be expected to leak slightly more than refinery valves, but not by a factor of four.

The commenter also disagreed with the LDAR model's assumption that the number of leakers increases linearly with time. As an example, the commenter said that the model estimates the percentage of leakers for an annual program to be at least 16 percent (1.3% x 12 months, plus minimum level). The commenter stated that this high rate is why EPA does not believe it is reasonable to (allow leakers to) accumulate for greater than 1 year.

Response: In response to the first commenter's remarks, the LDAR model does not contain any data; it is merely an algorithm to "model" a leak detection and repair program. To use the model, monitoring data must be provided as input. The LDAR model as presented in the AID is the basis for the cost analysis of controlling valve and pump seal emissions. However, the use of the model for natural gas processing plants was based on the best leak data available, including gas plant emission factors. These model results are presented in Table E-1 of the BID for the proposed standards and in Docket Item II-B-18.

The second commenter contends that the rate of leak occurrence for valves used by EPA as inputs to the LDAR model is high; and the model assumes that the number of leakers increases linearly with time. The 1.3 percent rate of leak occurrence for valves is based largely on data from SOCMI plants and has been corroborated by API valve maintenance data from petroleum production operations (II-I-20, II-I-21). The EPA analyzed the API valve maintenance data and concluded that the API data support the estimates of leak occurrence and recurrence used by EPA for gas plants (II-A-9).

The LDAR model assumes a constant valve leak occurrence rate as mentioned by the commenter. However, this rate is applied by the model on only the non-leaking sources after each month. For example, the 1.3 percent occurrence rate mentioned by the commenter would result in 13 leaks per month during the first 6 months (for a plant with 1,000 valves), 12 leaks per month during the next 6 months and so forth until all 1,000 valves were leaking, which would require over 40 years at a 1.3 percent/month rate. Although another description of the rate at which leaks develop might be slightly more accurate, the method used in the LDAR model is based on reasonable assumptions necessary for modeling an average case. For example, valves within a plant may have different leak occurrence rates due to different designs, services, manufacturers, or frequencies of use. Modeling of such factors would require extremely complex information over long periods of time for every plant analyzed. Consequently, the LDAR model attempts to simplify the leak occurrence phenomena to represent an average case for all plants based on test data from typical processing plants.

The second commenter indicated that his company's refinery experience indicated a leak occurrence rate of 0.3 percent leakers per month, and that gas plants may be expected to have slightly higher occurrence rates. However, data provided by another commenter (IV-D-26) showed a 3.74 percent monthly occurrence rate at a gas plant recently tested, three times the occurrence rate used by EPA for the LDAR model input. Therefore, EPA considers these comments to confirm the reasoning used by EPA that, although occurrence rates will be widely variable, average valve leak occurrence rates can be used in developing model programs for cost-effectiveness analyses.

Comment: One commenter (II-B-23) stated that the LDAR model generates negative control efficiencies for some inspection frequencies.

Response: The commenter is pointing out an incorrect use of the LDAR model. A negative control efficiency theoretically is generated when the occurrence rate for a given inspection interval is greater than the initial leak frequency. This may occur at a plant with an overall occurrence rate of 1.3 percent, in which the leak rate increases after leak detection and repair.

4.8.2 Delay of Repair

Comment: Two commenters (IV-D-15; IV-D-35) requested that the delay of repair provisions in Section 60.632-8(a) be revised to read, in part, "Repair ... shall occur, however, at the first scheduled process unit shutdown." The commenter held that during unplanned shutdowns, operating personnel are trying to make repairs due to upsets or equipment malfunctions.

Response: The EPA agrees with the commenter that, during brief emergency shutdowns, operating personnel may not be available for repair of leaking components due to the importance of restarting the process. To make allowances for delay of repairs beyond an unscheduled shutdown in the case of shutdowns of too short a duration for operating personnel to make repairs, a process unit shutdown has been defined as longer than 24 hours. Since proposal, the definition of "process unit shutdown" has been revised to exclude from the definition any unscheduled work practices or operational procedures that stop production from a process unit or part of a process unit for less than 24 hours. This definition is in Subpart VV, standards for equipment leaks of VOC in SOCMI, and is considered reasonable for gas plants as well.

Comment: One commenter (IV-F-4) stated that Section 60.632-8 of the proposed standards should have provisions to extend the repair interval beyond 15 days in the event that replacement parts, equipment, or personnel are unavailable. The commenter held that the delay of repair requirements should be revised because these provisions unfairly penalize the small gas processor. The commenter claimed that large inventories of spare parts cannot be maintained at small plants due to the high capital costs, tax considerations, and space requirements involved.

Response: The provisions of Section 60.632-8 of the proposed standards allow for delay of repair beyond a process unit shutdown in the event sufficient supplies were stocked and then depleted. As recognized by the commenter, this "parts depletion" provision does not apply to the normal 15-day repair period for sources not requiring a process unit shutdown. Many smaller gas plants are remotely located and may maintain little, if any, stock of spare parts. However, many of these plants would have an existing source of readily available parts to prevent unnecessary plant downtime. Most parts should be available on an immediate-delivery basis, either from a central location from the company owning the plant, or from parts distributors.

Even though it is conceivable that a plant could have a monitoring period in which a greater than normal number of repairs requiring spare parts was necessary and depleted the inventory of spare parts, such situations should be rare. In any event, provisions for delay of repair beyond the normal 15-day period should not be necessary. Since most repairs requiring parts replacement would require that the leaking component be removed from service, the component requiring the parts would either be one which can be isolated from the process for repair or one which could not be repaired until the next shutdown. In the latter case, the delay of repair provisions allow for delay beyond shutdown if sufficient stock of spare parts is depleted.

For components isolated from the process for repair, the leaking component may remain isolated until parts are acquired. Repair of these components legally could be delayed indefinitely (provided there are no VOC in the line), and no provision for spare parts, other than the one provided in Section 60.632-8(b), is required.

4.8.3 Sealless Equipment

Comment: One commenter (IV-D-20) noted that EPA discusses sealless pumps as not having a potential leak area and then requires initial and annual performance tests. The commenter questioned why leakless equipment requires any monitoring and suggested that the requirements for monitoring leakless equipment be deleted.

Response: The standards require an initial performance test to verify that a piece of leakless equipment meets the "no detectable emissions" limit and annual rechecks to ensure continued operation with "no detectable emissions." The EPA believes that these requirements are necessary to verify the integrity of the equipment at installation and throughout its operation. Leakless equipment may fail, for example, as a result of corrosion or wear. For these reasons, EPA has determined that initial and annual performance tests are necessary.

4.8.4 Repair Period

Comment: Several commenters (II-B-23, II-D-10, II-D-30, IV-D-19, IV-D-20, IV-D-27, IV-D-30, IV-D-34, and IV-D-35) objected to the repair period requirements. Commenters II-B-23, IV-D-27, IV-D-34, and IV-D-35 requested an extension of the first attempted repair period from 5 calendar days to 7 and 15 days. Another commenter (IV-D-19) requested that the final repair requirements be changed to at least 30 days. Reasons offered for these changes include:

1. Replacement parts are not available within 15 days, therefore, gas plants would have to maintain an expensive inventory with no significant air quality benefit (IV-D-19),
2. Remoteness of plants, inclement weather, and manpower availability at small plants justify extending the repair time (IV-D-27),

3. An extension would allow a regularly scheduled maintenance crew to handle repairs, whereas retention of the 5-day limit would require contractor maintenance personnel to be paid for expensive overtime and holiday work and create scheduling problems (IV-D-34 and IV-D-35), and

4. At most gas processing plants personnel are not available to repair all leaks within a 5-day period. Most new plants are designed to run unattended for most of the day.

Another commenter (IV-D-20) asked that the 5-and 15-day repair time limits not apply to equipment for critical valves, pumps, and compressors used to keep the process operational. There is no reason to specify a repair period for equipment that can be taken out of service.

Response: The standards require that a first attempt at repairing a leaking equipment should be accomplished as soon as practicable but no later than 5 days after detection of a leak. Attempting a first repair of the leak within 5 days will help maintenance personnel identify the leaks which can be repaired without shutdown of the process unit. Equipment that continue to leak after simple field repair attempts must be repaired within 15 days following initial leak detection. This interval provides time for properly isolating equipment that require more than simple field repair. The 15 days provides sufficient time to schedule and effect on-line repairs that a shorter period might not allow. Provisions have been made for delaying repair of valves in critical service that cannot be bypassed. The two repair period requirements provide efficient reduction of emissions and allow sufficient time for flexibility in scheduling repairs of leaking equipment. A 15-day period for initial repair would simply permit delays in repairs that could otherwise be accomplished quickly.

Most valve repairs can be done quickly and involve simple maintenance procedures, such as packing gland tightening and grease injection. This is evident from compliance experience of refineries with the South Coast Air Quality Management District Rule (Rule 466.1) for valves which require repair within 2 working days. A 5-day period for initial attempts provides sufficient time to schedule field repair.

Valves that require off-line repair (25 percent is estimated in the BID for the proposed standards, Chapter 8) may require new packing or valve parts (i.e., gland flange or nut); however, these spare parts and others would be stocked on-site for routine maintenance. Therefore, stocking of these parts does not represent a burden imposed by the standards.

The EPA realizes that many gas processing plants would be located in remote areas, have limited manpower availability, and subject workers to inclement weather. Consequently, EPA has exempted small nonfractionating plants from the leak detection and repair requirements based on the cost effectiveness to employ corporate office personnel or contractors to perform the leak detection and repair program. The EPA believes that the leak detection and repair requirements, including the repair periods, are reasonable for all fractionating plants and nonfractionating plants with a capacity of 10 MMscfd or more.

4.8.5 Process Unit Shutdown

Comment: One commenter (II-D-10) remarked that some sources of emissions in gas plants cannot be repaired until there is complete plant shutdown, adding that a mandated routine shutdown for leak repair would result in greater emissions than would be saved by repair. The commenter noted that the majority of gas plants do not have periodic turnarounds as refineries do because gas plants process gas as it is produced from field wells; otherwise gas products are lost.

Response: The standards do not require routine shutdown for repair of leaks for the reason cited by the commenter that a mandated routine shutdown could result in greater emissions than would be reduced by repair. The EPA does allow owners or operators to delay repair of leaking valves, pumps, and relief valves beyond 15 days after leak detection if the component cannot be repaired without a shutdown. For valves, EPA allows a delay of repair beyond a facility shutdown if the entire valve assembly is required to be replaced, provided the plant owner or operator can demonstrate that sufficient stock of spare valve assemblies was maintained before depletion of the stock of spare parts.

Comment: One commenter (IV-D-29) requested that the word "production" in the definition of "process unit shutdown" be amended so that it is clear it means production of natural gas and/or liquids.

Response: The definition of "process unit shutdown" clearly states that a shutdown is a termination of "production from a process unit or part of a process unit." Since a "process unit" is also defined as equipment assembled for the extration and fractionation of natural gas liquids, the word "production" in the definition clearly means the extraction or fractionation of natural gas products.

It should be noted that natural gas production from the field can continue while the processing plant is shut down.

5.0 APPLICABILITY OF STANDARDS

5.1 DEFINITIONS

5.1.1 Natural Gas Processing Plant

Comment: Eleven commenters (IV-D-10; IV-D-11; IV-D-14; IV-D-15; IV-D-16; IV-D-17; IV-D-19; IV-D-34; IV-D-35; IV-F-1c; and IV-F-1e) requested that the definitions of "natural gas processing plant" and "processing unit" in Section 60.631 of the proposed standards be clarified to exclude units that EPA intended to exempt, such as field separators and well site production facilities. Most of these commenters suggested that changing the word "separation" in the definition of natural gas processing plant to "extraction" would imply units operating with a forced process, while "separation" implies simple removal by gravity or natural condensation.

Another commenter (IV-D-11) asked that EPA confirm in the promulgated standards that the regulations do not apply to facilities such as sour gas treatment facilities that separate impurities other than natural gas liquids from the field gas. Other commenters (IV-D-14; IV-D-16; IV-D-34; and IV-F-1e) asked that facilities not intended to be covered by the regulation be clearly excluded. One commenter (IV-D-19) asked that the exemption given in Section 60.630(e) clarify that "not located at" means not within the boundaries of the gas plant.

One commenter (IV-D-15) requested deleting subparagraphs (1), (2), and (3) of Section 60.630(a), and stating in paragraph (a) that "The provisions of this subpart apply to specific process units within natural gas processing plants." The commenter favored this change because it eliminates the need for the field facility exclusion in paragraph (e) of Section 60.630 and because, he argued, compressors should not be designated as affected facilities, but should be specifically excluded.

Response: In the proposed standards, a "natural gas processing plant" (gas plant) is defined as "any processing site engaged in the separation of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both." The definition was intended to exclude facilities that remove liquids from field gas by means other than a forced process (e.g., gravity or natural condensation). Therefore, EPA has revised the definition of "natural gas processing plant" in the promulgated standards to read "... any processing site that extracts natural gas liquids from field gas." The definition of "process unit" has also been revised by substituting the word "extraction" for the word "separation."

The EPA considers sour gas treatment facilities to be affected facilities (i.e., subject to the standards) unless they are not located at an onshore natural gas processing plant. The EPA knows of no reason (and the commenters did not provide any reasons) why sour gas treatment facilities should be exempted from the standards. If these facilities have equipment in VOC service, then they should be covered by the standards.

Subparagraphs (1), (2), and (3) of Section 60.630(a) clearly define the affected facilities for natural gas processing plants. Compressors are affected facilities, as explained in Section 60.630; therefore, subparagraph (2) is necessary. Paragraph (e) is also necessary, regardless of how paragraph (a) is worded, to make it clear which process units and compressors are exempt from the requirements of the standards.

5.1.2 Liquified Petroleum Gas and Natural Gas Liquids

Comment: One commenter (IV-D-10) suggested adding the following definitions to the standards:

- "Liquified petroleum gases" mean ethane, propane, normal butane, and/or iso-butanes or mixtures of these liquified gases.
- "Natural gasoline" means a liquid composed of pentanes and heavier hydrocarbons or mixtures of pentanes, heavier hydrocarbons, and/or lighter hydrocarbons.

Another commenter (IV-F-1; No. 5) suggested changing the term "natural gas products" to "liquified petroleum gases."

Response: As noted by the first commenter, liquified petroleum gases (LPG) generally consist primarily of propane and butane, while "natural gasoline" consists of pentanes and/or heavier hydrocarbons. Both of these streams are considered VOC by EPA and are, therefore, subject to the requirements of the standards. The EPA used the terms "field gas" and "natural gas liquids" to define the feedstock and product streams in natural gas processing plants, and the term "natural gas products" to define the individual products (such as LPG or natural gasoline) resulting from the fractionation of natural gas liquids. As such, both liquified petroleum gases and natural gasoline as defined by the commenter would be included in the term "natural gas products," which is contained in the definition of "natural gas processing plant." Since "LPG" and "natural gasoline" could have specific meanings, the use of these terms could result in exclusion of other natural gas products that were intended to be included. Therefore, EPA will continue to use the terms "natural gas liquids" and "natural gas products" as generic terms for natural gas processing plant product streams.

5.1.3 VOC

Comment: One commenter (IV-D-20) requested that ethane handling equipment be exempt from the requirements of the standards. The commenter stated that the preamble indicated that methane and ethane have negligible photochemical reactivity, but the definition for natural gas liquids does not exclude ethane. The commenter indicated that this lack of exclusion would result in requiring inspection of ethane handling components.

Another commenter (IV-D-25) requested that EPA revise the definition of VOC in Section 60.2 of the General Provisions to specifically exclude methane and ethane. The commenter thought a revised definition was necessary because Reference Method 21 detects any organic compound and nonreactive organic compounds (such as methane and ethane which are not considered VOC by EPA). The commenter noted that methane is used as a calibration gas in Reference Method 21.

Response: The first commenter is correct in stating that the definition for natural gas liquids (NGL) does not exclude ethane. However, a piece of equipment is covered by the standards if the stream is in VOC service, not NGL service. The standards allow the exclusion of substances not considered photochemically reactive by EPA when determining the percent VOC in the process fluid (i.e., determining whether a piece of equipment is in VOC service). The VOC content is determined by the ASTM methods E-260, E-168, and E-169, not by Reference Method 21. Therefore, the fact that ethane is included as an NGL does not necessarily mean that ethane-handling components are covered by the standards. Thus, the exclusion of ethane from the definition of NGL or a revision to the definition of VOC in the General Provisions is unnecessary.

5.1.4 Control Device

Comment: One commenter (IV-D-36) recommended that EPA revise the definition of a control device to read that a control device "means an enclosed combustion device, vapor recovery system, or flare, designed in accordance with the provisions of Section 60.632-9."

Response: The EPA does not believe that it is necessary to amend the definition of control device as recommended by the commenter. Section 60.631 of the proposed standards provides a definition for a "control device," and control device requirements are given in Section 60.632-9, which has been revised as discussed in Section 4.7.

5.1.5 Heavy and Light Liquid Service

Comment: One commenter (IV-D-35) recommended changes in the definitions of "heavy liquid service" and "light liquid service." The commenter indicated that all liquid service streams are currently excluded from the "heavy liquid service" definition. For light liquid service, the commenter suggested using the ASTM test methods incorporated in Section 60.635(d)(2) instead of the stream VOC content as used in Section 60.635(e).

Response: The commenter has correctly noted two errors in the regulation, which have been corrected in the promulgated standards. One error, the definition for "in heavy liquid service," was corrected to read "... means that a piece of equipment is not in gas/vapor service or in light liquid service." The word "light" was inadvertently omitted from the definition.

The second error noted by the commenter is in the definition for "in light liquid service." The EPA incorrectly cited paragraph (e) of Section 60.635 instead of paragraph (d)(2) in referring to the determination of equipment in light liquid service. This error has also been corrected in the promulgated standards by incorporating the definition in Subpart VV, as amended.

5.1.6 Quarter

Comment: Two commenters (IV-D-35 and IV-D-36) requested that EPA change the definition of "quarter." One commenter (IV-D-36) recommended that the definition read that quarter ". . . means a 3-month period, commencing on January 1, April 1, July 1, and October 1 of each year" because the gas processing industry generally uses this definition for all other internal, State, and Federal reporting requirements and, consequently, standardization of the NSPS reporting requirements with industry practices would facilitate compliance with these requirements.

The second commenter (IV-D-35) recommended that NSPS monitoring start with the first quarter after the first 180 days have elapsed. The commenter suggested changing the definition of "quarter" in the standards from "The first quarter concludes on the last day ..." to "The first quarter commences the next day after the last day of the last full month during the 180 days following initial startup." The commenter wrote that ending the first quarter during the 180-day startup period essentially reduces the startup period to 90 days while gas plants typically require about 180 days to startup, debug, balance and establish routine operations.

Response: The EPA does not wish to force industry into specific calendar dates for monitoring activity. Therefore, calendar dates are not used for defining quarters; however, a plant owner or operator may choose to use the calendar quarters suggested by the commenter provided the first date of the calendar quarter is no later than the day after the last day of the last full month during the 180 days following initial startup.

The regulation specifies that the plant be in compliance with the standards within 180 days of initial startup, not after the 180-day period. The EPA has been given no data or documented information in support of the second commenter's claim that gas plants typically require the full 180 days to prepare to be in compliance with the standards. Startup times for gas plants are not expected to be any different from startup times for refineries or chemical plants.

5.1.7 In VOC Service

Comment: Numerous commenters (II-B-23; II-D-30; IV-D-13; IV-D-14; IV-D-15; IV-D-16; IV-D-17; IV-D-19; IV-D-21; IV-D-23; IV-D-24; IV-D-25; IV-D-26; IV-D-27; IV-D-29; IV-D-30; IV-D-31; IV-D-33; IV-D-34; IV-D-35; IV-D-36; IV-D-37; IV-F-1a; IV-F-1b; IV-F-1e) requested that EPA raise the VOC concentration limit for "VOC service" from 1 weight percent VOC to either 10 volume percent VOC or 10 weight percent VOC. Several reasons were presented by the commenters, including:

- Use of a 10 weight percent VOC limit would make the standards consistent with other equipment leak standards.
- Raising the limit on VOC concentration would concentrate attention on equipment that is more likely to exhibit VOC leaks and would result in more cost effective control.

- Under the current limit of 1 weight percent, the commenters indicated that many "residue gas" streams, which EPA intended to exempt, would be covered. Other commenters (IV-F-1a; IV-D-26; IV-D-36) stated that an industry-wide survey indicated that a 10 weight percent cutoff would exclude dry gas service components at most of the plants surveyed, and that EPA's data base for establishing a 1 weight percent limit was inadequate.

- One commenter provided plant size and residue gas VOC content data for over 100 plants to illustrate his point. Similarly, another commenter (IV-D-21) wrote that only 13 out of 36 of his company's operating plants produce residue gas that is less than 1.0 weight percent VOC, while 29 of these same 36 plants have residue gases that are less than 10 weight percent VOC.

- Another of the commenters (IV-F-1e) said that a 1 weight percent limit implied an uncommonly high degree of liquid removal.

- Two commenters (IV-D-15, IV-D-35) wrote that the API/Rockwell Study shows primarily methane streams (residual or sales gas), a non-VOC, would be exempt by this 10 percent criterion.

- One commenter (IV-D-17) indicated that "pipeline quality" gas often contains more than 1 weight percent VOC and indicated that EPA had told him that pipeline gas was intended to be excluded.

- Other commenters (IV-D-31; IV-D-35) suggested, as an alternative to or in addition to changing the definition of VOC service, that residue gas be classed a priori not in VOC service.

- One commenter (IV-D-19) stated that a refinery valve handling a 10 weight percent VOC stream has roughly the same health effects and control costs as does a valve in a gas plant handling a 10 weight percent VOC stream. The commenter added that EPA's argument that 1 to 10 weight percent streams contribute a significant portion of gas plant emissions is not sufficient justification to control that portion, especially when the total source category emits very little.

- One commenter (IV-D-24) remarked that many automatic control valves are operated using "natural gas" with VOC content greater than 1.0 percent by weight. Consequently, these valves have to be replaced or a new instrument air compressor must be purchased. The commenter also stated that product natural gas from the average gas plant has a VOC content in the range of 3 to 8 percent by weight. The commenter thought the VOC content should be raised to 4 mole percent or 8 weight percent.

Response: In setting the VOC concentration limit, EPA took into consideration the VOC content below which equipment leak controls may not be cost effective. In the case of synthetic organic chemical plants and petroleum refineries, the costs of controlling the small number of streams containing less than 10 weight percent VOC appeared to be unreasonable in light of the emission reduction potential. Therfore, EPA considered 10 weight percent VOC to be an appropriate VOC concentration limit for those standards. In contrast, gas processing plants can have a large number of components in streams containing between 1 weight percent and 10 weight percent VOC, and the cost effectiveness of controlling emissions from these components is reasonable. Thus, the lower VOC concentration limit appeared to be warranted as a way to cover these streams.

The underlying concern of the commenters was that, while EPA stated in the preamble that product natural gas (residue ("dry") gas) was to be excluded, the 1.0 weight percent VOC limit was so low that many residue gas streams would be covered by the standards. To support this contention, the Gas Processors Association (GPA) provided data for throughput, non-organic content, and VOC content for the residue gas streams from over 100 plants. An analysis of these data is presented in Docket Item IV-B-10. Some of the plants listed in the GPA survey had residue gas VOC contents below 1.0 weight percent VOC, with many less than 0.1 weight percent VOC. Most of the plants had residue gas streams containing between 1.0 percent and 10 weight percent VOC, and a few plants had residue gas streams exceeding 10.0 weight percent VOC. The GPA data illustrated to EPA that 1 weight percent VOC was not an appropriate limit to exclude residue gas streams, since residue gas streams can often contain more than 1 weight percent VOC. Therefore, the Administrator decided to raise the limit. Considering that the costs of controlling most gas plant streams, other than wet gas streams, containing less than 10 weight percent VOC would be too high for the emission reduction that would be achieved, a VOC concentration limit of 10 weight percent was selected as a representative limit for the "in VOC service" definition. Therefore, the definition of "in VOC service" has been changed in the promulgated standards to refer to a 10 weight percent VOC content.

However, the original intent in utilizing a 1.0 weight percent VOC limit was to ensure that inlet (wet) gas streams were subject to NSPS control, since emissions can be reduced at reasonable costs from inlet gases. Therefore, the promulgated standards require that all equipment in wet gas service be controlled (except wet gas reciprocating compressors), regardless of VOC content. Since wet gas streams may vary around 10 weight percent VOC, this requirement will prevent repeated testing to determine VOC service and will clarify the intent of the standards for plant owners, operators and enforcement personnel.

Comment: One commenter (IV-D-37) recommended that Section 60.635(e)(1) be revised to require that a determination that a piece of equipment is not in VOC service should only apply during normal and ordinary operations. According to the commenter, this change is necessary to eliminate brief periods during upset conditions when the line may contain heavier hydrocarbons than normal.

Response: The General Provisions, Section 60.8(c) of the Clean Air Act, cover operations during upset conditions. Specifically, Section 60.8(c) states that:

Operations during periods of start-up, shutdown, and malfunctions shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

Therefore, the commenter's suggested revision is unnecessary.

5.1.8 Vacuum Service Components

Comment: One commenter (IV-D-20) agreed with the exclusion for vacuum equipment. The commenter requested that common English equivalents of measurement be included in parenthesis where SI units are given.

Response: The EPA has not found it necessary to revise the definition for "in vacuum service" by including the appropriate English equivalent measure to the SI units given. The conversion from kilopascals (kPa) to the appropriate English equivalent, pounds per square inch (psi), is 6.895 kPa = 1 psi. Therefore, the definition for in vacuum service expressed in English units would mean equipment operating at an internal pressure that is at least 0.725 psi below ambient pressure.

5.1.9 Connectors

Comment: One commenter (IV-D-20) stated that requirements to repair leaking pumps and valves in heavy liquid service, relief valves in light and heavy liquid service, and flanges and other connectors are generally reasonable. The commenter did not agree that it is reasonable to define a "connector" as a welded joint. The commenter argued that such connections do not leak and should not be subject to these requirements.

Response: The EPA maintains that it is reasonable to include a welded joint in the definition of a "connector". Welded joints may leak due to an improper seal or fitting, or leaks may develop over time due to corrosion or deterioration of the weld. Therefore, welded joints, like other connections, are subject to the standards as specified in Section 60.632-7 of the proposed standards. If evidence of a potential leak is found by visual, audible, olfactory, or other detection method, the connection must be monitored within 5 calendar days (or assumed to be a leaker); a first attempt at repair must be made within 5 days of detection; and repair must be completed as soon as practicable, but no later than 15 calendar days after the leak is detected.

5.2 SELECTION OF SOURCES

5.2.1 Valves and Open-Ended Lines

Comment: One commenter (IV-D-3) noted that valves and open-ended lines account for 79 percent of the VOC emissions from gas plants and questioned why the standards are not limited to these two sources.

Response: Based on the use of the revised compressor seal emission factors (BID for proposed standards, Appendix G), valves and open-ended lines represent approximately 70 percent (191 Mg/yr for valves and open-ended lines and 82.8 Mg/yr for other sources combined from Model Plant B) of VOC emissions from gas plants.

The EPA agrees that valves and open-ended lines represent the largest sources of gas plant emissions. However, the baseline emission factors in the BID for the proposed standards, Table 7-2, as corrected in the appendices, show that pressure relief devices, compressor seals, and pump seals are also significant emission sources. Together these sources account for 49.2 Mg/yr of VOC emissions from a typical plant. The emissions from these sources are reasonable to control as shown in Table 3-1.

In selecting best demonstrated technology (BDT), EPA selected standards for each type of component in gas plants with demonstrated, cost-effective control techniques. Since the general purpose of NSPS is to require new facilities to incorporate best demonstrated technology as they are being constructed, and cost-effective controls are available for compressors, pumps, and pressure relief devices, these sources are also included.

5.2.2 Heavy Liquids

Comment: One commenter (IV-D-15) wrote that the standards should delete the monitoring requirements for components "in heavy liquid service." The commenter noted that these components have a low potential for VOC emissions.

Response: The proposed standards (Section 60.632-7) do not require routine monitoring of components in heavy liquid service. Components in heavy liquid service are not as likely to develop leaks as are gas service or light liquid service components. However, heavy liquid service components that do leak have emission rates comparable to components in gas or light liquid service. Therefore, the standards do require that leaks detected by visual, audible, or olfactory means be measured to determine if the leak results in an instrument reading of 10,000 ppm or greater and, if so, that the leaks be repaired as soon as possible within 15 days, with a first attempt at repair within 5 days. The operator could repair any leaks found in heavy liquid service without prior instrument measurement, if desired.

5.2.3 Small Valves or Lines

Comment: Several commenters (IV-D-15, IV-D-20, IV-D-22, IV-D-23, IV-D-26, IV-D-36, and IV-D-37) wrote that small valves or lines should be exempt from the standards. Commenters requested exemptions for valves ranging from 2 inches or less to 1/2-inch or less. The commenters contended that eliminating small valves from the routine monitoring requirements would greatly reduce recordkeeping, identification, and reporting requirements. The commenters claimed that small valves tend to leak less, both in frequency and amount of leakage, and contribute a relatively small percentage of total fugitive VOC emissions at gas processing plants. The commenters also argued that exempting these valves from monitoring requirements would reduce overall plant monitoring costs.

Response: In developing similar standards for petroleum refineries, EPA analyzed both the costs of small valve repair as compared to the BID average repair cost estimates and the emission factor dependency on valve size (Docket Item IV-B-11). These analyses indicate that the emission rates from leaking valves are independent of valve size and that repair of small valves is no more difficult or costly than repair of larger valves. The EPA concluded that, since both the environmental benefits and cost of control for small valves are the same as larger valves, small valves are cost effective to control.

The emission source test data presented in Appendix C of the BID for the proposed standards were collected at six natural gas/gasoline processing plants by EPA and industry. Valves of all sizes were monitored in these tests, and valve size was determined not to be a factor. The emission factors developed from these test data are based on all valves in gas processing plants. The basis of the standards for valves included all valve sizes and was determined to be cost effective. Therefore, an exclusion for small lines and valves is not warranted and is not included in the promulgated standards.

5.2.4 Small Compressors

Comment: One commenter (IV-D-21) was concerned that the standards for compressors apply to all sizes of compressors including those used to recompress vapor from storage tanks, refrigerate gas, boost regeneration gas, and even collect emissions from a larger compressor. The commenter complained that without a horsepower cut-off in the designation of a compressor as an affected facility, the replacement or modification of a small compressor at an existing plant could require installation of a complete vent control system for all the compressors at a plant.

Response: As with other fugitive emission sources, EPA has found no relationship between component size and emissions. Emission test data were collected from all sizes of components and compressors, so that the emissions and cost effectiveness of controlling compressors are based on compressors of all sizes. Consequently, EPA knows of no reason to exempt small compressors based on horsepower.

5.2.5 Difficult-to-monitor Valves

Comment: A number of commenters (IV-D-23; IV-D-26; IV-D-30; IV-D-33 and IV-D-36) recommended that EPA exempt insulated valves from the monitoring requirements of the proposed standards. The commenters stated that some valves in natural gas plants require insulation because they are in very hot or very cold service. Monitoring of these valves would require removal and replacement of the insulation, often by an insulation contractor, which would be both time consuming and costly. Two commenters (IV-D-30; IV-D-33) noted problems with icing on some cryogenic temperature valves, delaying replacement of the insulation until a shutdown so that components may warm up.

Response: The EPA recognizes that additional time would be required to remove and replace valve insulation to monitor or repair these components. There may be problems associated with removing insulation (e.g., ice formation). Nevertheless, insulated valves can be monitored as close to the potential leak source as possible without removing the insulation. If a leak is detected, repairs can be scheduled within 15 days without having to delay repair until the next turnaround.

The EPA determined that it is cost effective to repair insulated valves that leak rather than delay repair until the next unit turnaround (Docket Item IV-B-12). Therefore, the standards for valves, including insulated valves, require that these components be monitored as close to the source as practicable without requiring removal of the insulation. If a leak is detected, as with other valves, repair of insulated valves must be attempted as soon as possible within 15 days with a first attempt at repair within 5 days.

5.3 SELECTION OF AFFECTED FACILITIES

Comment: One commenter (II-B-23) suggested that the list of VOC fugitive emission source categories that are excluded from coverage by the gas plants standards should also include other VOC sources such as VOL storage and benzene storage tanks.

Response: The purpose of the list was to exclude sources from the gas plants standards if they were also subject to other standards for equipment leaks of VOC. These standards include promulgated standards for equipment leaks from petroleum refineries (Subpart GGG), SOCMI plants (Subpart VV), and benzene equipment leaks (Part 61, Subpart J). The volatile organic liquid (VOL) storage standard is based on emissions from process vents rather than equipment leaks. As a result, a VOL storage tank (such as an NGL receiver tank) at a natural gas processing plant would be covered by Subpart K (VOL storage) for vented emissions and by Subpart KKK for equipment leaks from valves, pumps, compressors, open-ended lines, and pressure relief devices.

Comment: One commenter (IV-D-20) took issue with EPA's presumption that a narrower designation of the affected facility was proper in determining regulatory applicability. The commenter claimed that a narrow definition may be proper at gas plants located in ozone nonattainment areas and subject to New Source Review, but is improper when applied to all gas plants. The commenter stated that the application of NSPS by way of BACT requirements associated with PSD permitting is subject to the PSD source definition and, therefore, requested that the narrower designation of affected facilities be removed from the NSPS. The commenter specifically requested that each compressor train rather than each individual compressor be defined as the affected facility, because the enclosing of distance pieces would create potential explosion problems on certain affected units. The commenter suggested that each compressor train be considered as modified only if aggregate emissions from that train increase.

Response: The EPA uses the term "affected facility" in NSPS to designate either the individual piece of equipment or groups of equipment within a plant chosen as the "source" affected by a given standard. The term "affected facility" is used in NSPS to effect the greatest emission reduction at reasonable costs and cost effectiveness. This may result in a designation different from that used in PSD. The designation of affected facilities is based on EPA's interpretation of Section 111 of the Clean Air Act and on the judicial construction of its meaning [ASARCO, Inc., v. EPA, 578 F. 2d 319 (D.C. Cir. 1978)]. The designation of the affected facilities is fully explained in the preamble to the proposed standards (49 FR 2637-38). Furthermore, since proposal, EPA has excluded certain compressors from coverage under the standards (e.g., wet gas reciprocating compressors) that are generally located in trains or groups. The compressors that are still covered by the promulgated standards (e.g., NGL compressors) are generally isolated and are not located in trains. Therefore, EPA does not agree that a broader designation of compressors as an affected facility is appropriate. Instead, EPA has concluded that it is appropriate to designate each individual compressor as an affected facility.

Comment: One commenter requested a clarification to Section 60.632-1(f) of the proposed standards to protect owners of existing plants which have certain equipment designed for purposes other than control of emissions from arbitrary subjection to high emission control costs. The commenter offered the following revision: (f) Reciprocating compressors in wet gas service that are located at an onshore natural gas processing plant that does not have a control device designed for VOC emission control present at the plant site are exempt from the compressor seal control requirements of Section 60.632-3.

Response: As provided in the promulgated standards, EPA has exempted all reciprocating compressors in wet gas service. Therefore, the presence or design of a control device for these compressors is no longer relevant.

Comment: One commenter (IV-F-6) requested that the exemption for compressors that cannot be economically or technologically retrofitted with emission controls, as discussed in the preamble to the proposed standards, be incorporated as a specific paragraph in the standards.

Response: Because compressors are a separate affected facility, they would be exempt from reconstruction if controls are technically or economically infeasible as specified by the General Provisions (see Section 60.15(e)). Therefore, a specific paragraph exempting these compressors is not necessary. The determination of whether a reconstruction or replacement of a compressor is technologically or economically infeasible will be made by the Administrator on a case-by-case basis. Unlike the reconstruction provisions, modification does not consider technical or economic feasibility.

5.4 APPLICABILITY DATE

5.4.1 Applicability Date of Standards

Comment: One commenter (IV-D-35) recommended that the Administrator publish in the Federal Register notice of the retraction of the January 20, 1984, applicability date for purposes of the definition of a "new source." He stated that the history of other standards which have been promulgated indicates that careful review of comments by the Agency can result in substantial delay beyond the 90-day period imposed for promulgation by the Clean Air Act. The commenter further wrote that such action by the Administrator would be well within his inherent power and in keeping with the rationale of the Act, Section 111, while failure to take such action would impose severe and unnecessary burdens on industry, which the Clean Air Act intended to be mitigated.

Another commenter (IV-D-20) suggested that the promulgated standards be applicable to plants starting construction 180 days after promulgation rather than on the date of proposal. The commenter indicated that plants with existing construction permits, but not yet constructed, could require redesign or re-permitting. The commenter indicated that EPA should consider the potential economic impacts of the earlier applicability date.

Response: Proposal of the standards is legal notification that an owner or operator of a source will be subject to a standard. The Clean Air Act (Section 111(a)(2)) clearly states the Congressional intent that the proposal date will be the applicability date. Section 111(a)(2) defines the new sources subject to an NSPS as those sources built or modified after proposal, not after promulgation or some later event.

The proposal date is the applicability date unless the promulgated (or revised) standard is not based on, and achievable by, the same technology specified at proposal. This decision is consistent with EPA's practice of applying NSPS's to all sources built after proposal where the promulgated (or revised) standards are based on and achievable by the same technology as the proposed standards.

Section 111(a)(2) implements the basic Congressional objective of preventing new pollution problems and improving air quality as industry changes by requiring all new sources (built or modified after proposal) to use best demonstrated technology (BDT) in achieving emission reductions. Congress recognized the existence of some uncertainty as to the final standards that this technology must meet (S. Rep. No. 91-1196, 91st Cong. 2d Sess. (Senate Bill, §113(b)(2)). The passage of time between identification of BDT as the basis of a standard and the final specification of the performance required of that technology, therefore, is not relevant by itself. Under Sections 111(b)(1)(B) and 307(d)(10), an NSPS should be promulgated within 6 months of proposal. However, Congress did not intend that if promulgation took longer, the category of new sources should change. Commonwealth of Pennsylvania v. EPA, 618 F. 2d 991, 1000 (3rd Cir. 1980); 45 FR 8210, 8232 (February 6, 1980); United States v. City of Painesville, 644 F. 2d 1186 (6th Cir. 1981), cert. den. 102 S. Ct. 392 (1981); 49 FR 18076 (April 26, 1984).

5.4.2 Existing Sources

Comment: One commenter (IV-D-3) noted that the statement in Section 2.3 of the BID for the proposed standards indicates that "Standards of performance must... (3) be applicable to existing sources ..." and asked if the proposed standards might be modified at a later date to include existing plants.

Response: Section 2.3 of the BID for the proposed standards makes it clear that the standards are applicable to existing sources that are modified or reconstructed. The terms "modification" and "reconstruction" are defined in the General Provisions (see Sections 60.14 and 60.15, respectively). The definitions and their applicability to the standards are discussed in Chapter 5 of the BID for the proposed standards.

Comment: One commenter (IV-D-20) proposed that all compressors manufactured before the effective date of the standards be exempt from the vapor recovery system requirements of the standards. The commenter noted that EPA stated in the preamble that compressors are supplied with enclosed distance pieces and vented seals. The commenter disagreed with EPA's assumption that all new compression capacity results from installation of new units. The commenter pointed out that many newly installed compressors are existing units that have been rebuilt. Hence, retrofitting controls onto these rebuilt compressors may result in considerable delay and expense.

Response: The effective date of the standards is the date of promulgation; however, all newly installed compressors at a plant, rebuilt compressors and factory new compressors, are subject to the standards if they are constructed after the applicability (proposal) date of the standards (January 20, 1984), unless they are specifically exempted (e.g., wet gas reciprocating compressors, or not "in VOC service"). The EPA made no attempt to correlate the number of new compressors with the amount of new gas to be produced. New compressors will be well controlled, and rebuilt compressors will be controlled as well. As stated in a previous response to comment, compressors would be exempt from the reconstruction provisions of the General Provisions if controls are technically or economically infeasible (Section 60.15(e) of the General Provisions).

Furthermore, since proposal, EPA has decided to exempt all reciprocating compressors in wet gas service. Therefore, the only reciprocating compressors covered by the standards are those in NGL service.

5.5 ALASKAN NORTH SLOPE

Comment: One commenter (IV-F-1d; IV-D-28), in both written comments and public hearing testimony, requested that natural gas processing plants located north of the Arctic Circle be exempted from the proposed standards. The commenter based his request on higher control costs per unit of emission reduction, as follows:

1. The commenter cited the higher cost of operation in arctic regions. Due to the extreme environment, processing facilities must be completely enclosed. Since plants are enclosed; space is limited, and safety is of paramount importance. Consequently, any design changes or retrofitting in arctic facilities is extremely expensive. Another important factor that increases the costs of operation in the Arctic is the high cost of labor. The commenter indicated that a technician in the Arctic costs approximately $124 per hour in 1980 (based on $33.50 per hour wage plus 370 percent administrative and overhead) due to the requirement for extensive life support systems and area labor costs.

2. The commenter thought that the basic rationale for uniform national VOC standards, to prevent the creation of local pollution shelters, is inapplicable in the Arctic. The degree of low solar insolation, the low concentration of photochemical precursors, and the cold ambient temperatures lead to a lack of photochemical ozone formation. Additionally, since processing facilities are enclosed, sophisticated gas detection systems are utilized to ensure safety which would detect leaks of VOC from processing equipment. Based on these factors, the commenter concluded that the standards would provide no emission reduction.

Response: The presence of an in-place hydrocarbon gas detection system does not necessarily ensure emission reductions. Several megagrams of VOC could be released to the atmosphere annually without the use of specific control techniques like those required by the standards. The commenter did not demonstrate that their system resulted in at least equivalent emission reductions as the standards. Based on EPA's experience, gas detection systems alone are ineffective for reducing equipment leaks of VOC. Thus, EPA has not exempted process units using these systems from the standards. The promulgated standards do, however, allow an existing control program to be continued if EPA determines that the program is at least equivalent to the requirements of the standards. 40 CFR 60.634

The EPA has studied the commenter's concerns and acknowledges that there are several unique aspects to the operation of natural gas processing plants north of the Arctic Circle. Because of the unique aspects of natural gas processing plants north of the Arctic Circle, the increased costs to perform routine leak detection and repair may result in an unreasonable cost effectiveness. These operations incur higher labor, administrative, and support costs associated with leak detection and repair programs because (1) they are located at great distances from major population centers, (2) they must necessarily deal with the long-term, extremely low temperatures of the Arctic, and, consequently, (3) they must provide extraordinary services for plant personnel. Therefore, EPA has decided that natural gas processing plants in the North Slope of Alaska are exempt from the routine leak detection and repair requirements of the standards. This exemption does not include the equipment requirements in the standards because installation of equipment controls is common practice in the region.

5.6 SMALL PLANTS

Comment: Several commenters (IV-F-1a, IV-D-15, IV-D-20; IV-D-21, IV-D-23, IV-D-26, IV-D-29, IV-D-30, IV-D-31, IV-D-36) requested that the small plant exemption size limit be revised. One commenter (IV-D-15) agreed with the small plant size limit of 10 MMscfd, but he, along with commenter IV-D-20, stated that the plant size exemption should be based on throughput instead of capacity. The commenter indicated that the same staff and economic considerations used by EPA to determine the appropriate cutoff apply to a throughput-based cutoff. Other commenters requested that the plant size limit be raised. Two commenters (IV-F-1a and IV-D-29) requested that the 10 MMscfd or less plant exemption include fractionating plants, and that the exemption be extended to somewhere between 35 to 50 MMscfd for nonfractionating plants.

Other commenters argued that the small plant size limit should be raised to 35 MMscfd. Several commenters (IV-D-21; IV-D-26; IV-D-36) provided cost and emission reduction data from a recently completed leak detection and repair program in support of a 35 MMscfd cutoff. One commenter (IV-D-30) offered several reasons for raising the small plant size limit to 35 MMscfd, including that EPA had overstated the potential emissions reduction, that the cost to implement the standards was underestimated by EPA due to the ignoring of the substantial clerical requirements, and EPA ignored the remoteness and lack of personnel at small facilities. Another commenter (IV-D-23) based his request to raise the small plant cutoff to 35 MMscfd (including fractionation) on EPA misconceptions of the average gas processing plant size. The average plant size, he contends, is biased by a few extremely large gas plants processing billions of standard cubic feet per day of natural gas.

Commenter IV-D-33 requested that EPA consider the extra travel time in getting to remote plant sites in setting the cutoff and the effect of extreme climatic conditions on travel schedule. In addition, the commenter stated that many gas plants with capacities of 10 MMscfd or less, whether they fractionate or not, are only partially attended or unattended. The commenter cited as examples two types of gas plants, straddle plants and casinghead plants, that differ in their staffing requirements and profitability because of their different numbers of pieces of equipment and feed rates. The commenter further stated that if his company hires an outside contractor, the recordkeeping and reporting requirements alone would be sufficient to warrant hiring a person at a cost of about $36,000 per year for each central office. The commenter concluded that there would be an obvious negative impact on plant efforts to improve manpower productivity.

Response: As presented in Appendix F of the BID for the proposed standards, EPA carefully analyzed the cost effectiveness of routine leak detection and repair programs for small, nonfractionating plants. The cost effectiveness values derived were presented graphically on page F-7 and are reproduced in Figure 5-1 on the next page. The graph in Figure 5-1 shows that the cost per megagram VOC reduced begins to increase rapidly as the plant throughput falls below 10 MMscfd. Therefore, 10 MMscfd represents an appropriate cutoff, and nonfractionating plants processing more than 10 MMscfd are subject to the monitoring requirements of the standards.

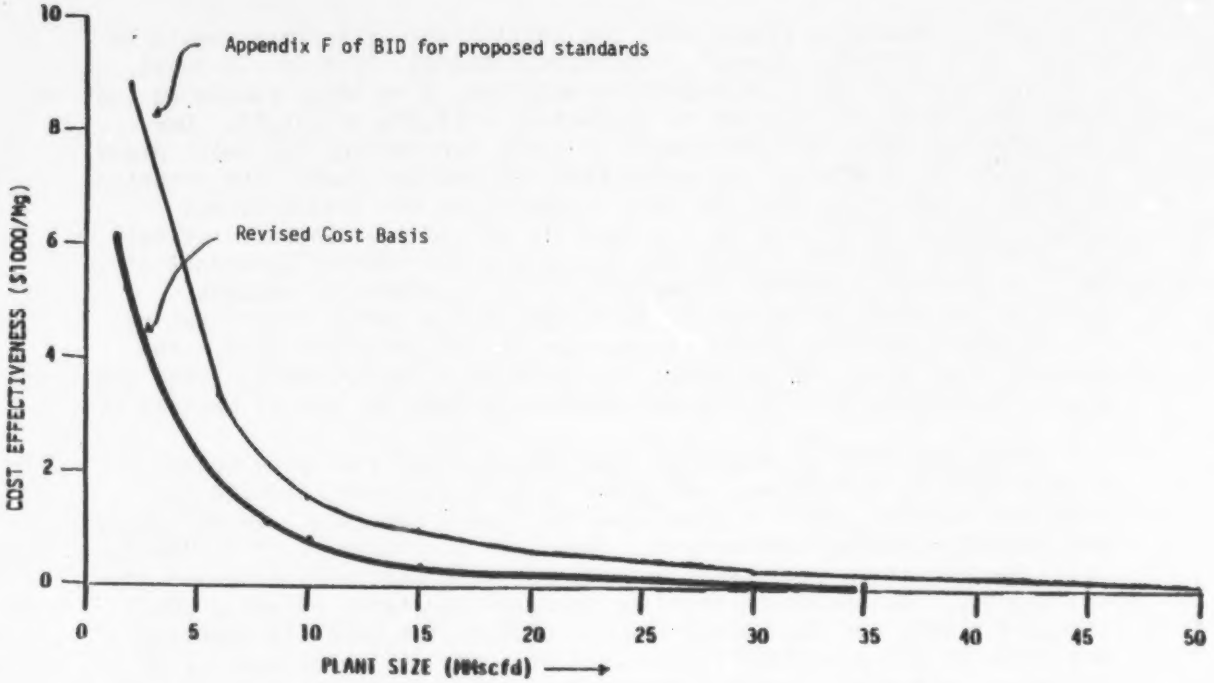


Figure 5-1. Cost Effectiveness versus Plant Size for Small Plants

Figure 5-1 also shows that the basis for the small plant leak detection and repair programs has been changed slightly since proposal. The primary revision to the cost basis was in changing the instrument cost. The analysis presented in Appendix F of the BID for the proposed standards was based on the assumption that each plant would maintain two monitoring instruments. However, if the monitoring is to be performed by contractors or central office personnel, it is likely that the instrument cost would be distributed among several plants. The revised cost is based on the assumption that the contractor or central office personnel would maintain two instruments but would use these instruments among five plants. Complete details of the revised costs are available in Docket Item IV-B-6.

The cost effectiveness values presented in Figure 5-1 are based on the cost of performing the required leak detection and repair program using either contractor or central office personnel. These costs include travel costs, as well as additional manhours for travel time. Since fractionating plants are more complex than nonfractionating plants, both physically and operationally, plants having fractionation trains are likely to have full-time operating and maintenance personnel available to perform the monitoring program "in house." The costs of such an "in house" program would be greatly reduced from a program requiring expenses for outside personnel and travel; consequently, an "in-house" program would result in a much better cost effectiveness. Fractionating plants are subject, therefore, to the requirements for routine monitoring regardless of capacity.

Some commenters requested that the small plant exclusion be based on throughput rather than capacity. Although the economics (as well as the emissions) of plant operation is highly dependent on the process throughput, capacity is the appropriate defining factor for excluding small plants. Throughput may vary from day to day; therefore, a small plant exclusion based on throughput would be unmanageable. An affected facility within the plant may be covered by the standards while operating under one capacity, but as the throughput decreases, the facility may be exempt. This system would require extensive recordkeeping and would be difficult to enforce. Since the plant capacity remains constant, and the plant throughput is limited by the capacity, the exclusion is based on plant capacity.

Comment: One commenter (IV-D-35) recommended that all intermittently attended gas plants be exempted from the proposed standards. The commenter claimed that in both casually attended and partially attended plant situations, the proposed standards could force premature abandonment of many remote or marginal wells, while plants manned 24 hours per day would, in all likelihood, have sufficient personnel to perform the monitoring, recordkeeping, and reporting required by the standards.

Response: The standards have an insignificant effect on the abandonment of wells because the costs of compliance with the standards are very small compared to the operating costs of a plant and the revenues generated by a plant. The EPA agrees with the commenter that there are some relatively small plants that operate without technically trained personnel being present because of the type of process that is performed there. The EPA was aware of such plants and considered the burden imposed upon small plants subject to the standards. At proposal, EPA exempted small nonfractionating plants (capacity of 10 MMscfd or less) from the standards. Assuming that nonfractionating plants would hire contractors or use central office personnel to perform the leak detection and repair program, EPA determined that it would not be cost effective to require these plants with 10 MMscfd or less capacity to perform the routine leak detection and repair requirements. The EPA believes, however, that fractionating plants require the presence of technically trained personnel having the ability to carry out responsibly a leak detection and repair program.

6.0 ENVIRONMENTAL IMPACTS

6.1 EMISSION REDUCTIONS

Comment: One commenter (IV-D-20) did not agree with the EPA estimates of the environmental benefit from implementation of the standards. The commenter wrote that EPA's assumptions regarding typical plant size, inventories of valves, and the number of plants to be built in the future overestimate emission reductions. The commenter requested that EPA re-evaluate the estimates.

The commenter noted that the emission reduction estimates are based on Model Plant B and argued that Model Plant B is not reflective of future gas plant sizes and designs. The commenter stated that most new gas plants will be cryogenic plants due to operational and economic reasons, and cryogenic plants have at least 50 percent fewer valves than EPA estimated for a "typical" Model Plant B.

The commenter also took issue with EPA's average emission factor of 6.3 kg/day for compressors, stating that since few new plants will have compressors in NGL service, the emission factor of 1.9 kg/day given by EPA for wet gas compressors should be used for all compressor calculations. Another commenter (IV-D-35) indicated that the Rockwell study (Docket Item II-I-20) showed the maximum compressor VOC emission factor is 1.5 lb/day (0.68 kg/day).

The commenter recalculated the emission reductions and estimated that the standards would control only 5,159 Mg/yr based on his assumptions that (1) Model Plant B contains 250 valves, (2) 1983 plant construction is not included, (3) compressor emission factor for Model Plants A, B, and C is 1.90 kg/day, and (4) emission reductions from capping open-ended lines are not included. The commenter also presented valve counts and plant capacity for four gas processing plants to support his argument that new gas plants would have fewer valves than EPA estimates. Based on data from 1982-1983 Hydrocarbon Processing Construction, the commenter stated that more than 60 percent of the new plants constructed were 25 MMscfd or less in contrast to EPA's estimated average capacity of 90 MMscfd.

Response: The EPA provides nationwide environmental impacts to illustrate the potential emission reduction associated with the standards on emission levels anticipated in the future. Promulgation of the standards, however, is based on the availability of demonstrated cost-effective control techniques. Even if the nationwide impacts presented in the preamble to the proposed standards were overstated, the point is that significant emissions are attributable to natural gas processing plants and that growth is predicted in the industry. In addition, cost-effective controls are available to reduce these emissions significantly. Therefore, new source performance standards should be promulgated for the industry.

The EPA noted several misconceptions in the commenter's analysis of nationwide impacts. Primarily, these faults are as follows:

- The commenter suggested using a compressor emission factor of 1.9 kg/day for all compressors, based on emissions from wet gas compressors, because few plants would have compressors in NGL service. Test data used by EPA in developing the proposed standards (as given in Appendix G of the BID for the proposed standards) showed that 34 percent of all compressors were in NGL service. Thus, the basis for using 34 percent NGL service compressors was actual test data rather than assumption.

- The commenter claimed that emission reductions from open-ended lines should not be considered a result of the NSPS, since lines in his plants are capped already. As evidenced by EPA plant visits and other comments pointing out difficulties in capping open-ended lines, most gas plants do not cap or plug open-ended lines. Therefore, it is unrealistic to exclude open-ended line emissions from the environmental impacts of the standards.

- The commenter based his emission reduction impacts on 250 valves in Model Plant B. The EPA recognizes that different designs for the same plant process will utilize widely variable numbers of components due to the level of control desired and the economics of construction. The valve counts used in the BID for the proposed standards were based on actual operating plants and represent average values. Since Model Plant B is intended to represent a relatively complex plant, such as a fractionating cryogenic plant or a nonfractionating refrigerated absorption plant, 750 valves is an appropriate count. Test data supplied by the Gas Processors Association for the Conoco Cashion plant showed 540 components (mostly valves) for a 30 MMscfd nonfractionating cryogenic plant, which would be a Model Plant A.

- The commenter disagreed with the inclusion of 1983 emission reductions. The emission reductions are presented to show a fifth-year impact, rather than the impacts by given calendar years. Although 1983 emission reductions will not occur, a new 5-year impact analysis would include 1987 reductions with the same results. The projected emissions and emission reductions from baseline levels of control through 1987 are presented in Table 1-1.

Comment: Another commenter (IV-D-22) believed that the emission reduction estimates were overstated. The commenter based his argument on the premise that most of the VOC emission reduction resulting from the standards will be achieved during the initial testing and that subsequent monthly tests are not justified. The commenter noted that initial testing at a gas plant found many leaking valves (over 100,000 ppm). The second test at this plant found 19 leaks out of 508 components. Of these, more than 50 percent had readings less than 50,000 ppm and only 1 greater than 100,000 ppm. Similarly, initial testing at another plant found many leaks with a soap score over 4, while a second test 19 months later found only two leaks with a soap score of 4.

The commenter presented a comparison between soap solution test results and results obtained using a Foxboro OVA-108 monitoring instrument as his method of establishing a relationship between measured VOC concentrations and leak rate. The commenter estimated that a monthly program would achieve an incremental reduction of 1,709 kg/yr more than an annual monitoring program. Therefore, the commenter concluded that annual monitoring of all components would serve both EPA's goal of establishing standards that will improve and maintain the environment and industry's goal of supplying the public with competitively priced products.

Response: The commenter contends that, although the leak frequencies used by EPA may be correct, new leaks occurring or recurring during the period between tests will be smaller than leaks found during initial testing. The assumption that more recent leaks will be smaller is true, as evidenced by the data presented by the commenter. However, the leak detection and repair programs are not intended as a means of repairing massive leaks, but rather as a means of preventing such leaks. The leaks discovered in each followup inspection are likely to be smaller than those found in the initial inspection which have developed over an extended period. This fact is the reason for shortening the monitoring period to monthly, as significant emissions can be prevented from occurring. If the leak detection and repair program were not performed, the leaks left undiscovered and unrepaired would eventually return to the magnitude found during the initial inspection. The commenter is partially correct in stating that most of the emission reductions occur in the initial monitoring period. In fact, the ongoing program provides the work practice to prevent these emissions from occurring again.

In response to the commenter's claims of low incremental emission reduction between monthly and annual monitoring, the standards allow special provisions to prevent the unwarranted monitoring of nonleaking sources. These provisions include monthly/quarterly monitoring for all plants and skip-period monitoring, or alternative standards, for low leak rate plants, which are discussed in detail in Section 6.2.

Comment: One commenter (II-D-10) noted that there is no scientific basis for assuming a "significant emissions reduction," since there is no definitive quantitative study demonstrating fugitive emission reduction from an inspection and maintenance program for refineries or gas plants. Furthermore, the commenter added that EPA had no technical basis for the transfer of chemical plant or refinery VOC emissions data to gas plants.

Response: This comment was made in May 1981 by API and is included at their request (IV-F-1e). Since that time, several leak detection and repair programs have been conducted by both EPA and industry. To assess the potential effects of leak detection and repair programs, EPA conducted emissions testing at gas plants and related facilities. The results of the EPA gas plant emissions tests, combined with the results of the API/Rockwell study, formed the basis for the gas plant emission factors (Docket Item II-A-23) and subsequent emission estimates. To assess the control technique (leak detection and repair) for valve, pump, and relief device emissions, EPA has performed a maintenance effectiveness study (Docket Item II-A-11) and has examined the results of on-going State and local equipment leak rules. These studies all support the effectiveness of leak detection and repair for reducing emissions. Although most of the studies were performed for refineries, the components regulated in gas plants are identical or very similar, and the same results are expected. Therefore, transfer of refinery/chemical data to gas plants is reasonable.

6.2 LEAK FREQUENCIES

Comment: One commenter (IV-F-2) submitted in-plant leak screening test data for a 20 MMscfd fractionating plant, a plant the commenter considered as typical of current industry design and construction. The first test was conducted on 4,195 components, including flanged and screwed connections. Using the API Soap Score Method and recording scores of 3 or greater as a leak, 61 components or 1.45 percent were found leaking. A second test was performed 18 months later on 722 components covered by the proposed standards (omitting flanged and screwed connections) using API soap and instrument methods. Each test method found 5 leaking components, all of which were valves corresponding to a 0.68 percent leak rate. The commenter also provided the total time taken to perform monitoring in each of these tests.

Based on these data, the commenter claimed EPA had both overestimated the emission reductions for the standards and underestimated the control cost.

Response: The EPA recognizes that some plants will have a low rate of leaks, either due to good maintenance practices or other factors, and also recognizes that frequent leak monitoring for such low leak facilities is not cost effective. Consequently, EPA provided standards for valves in which nonleaking valves may be monitored less frequently. For example, in the commenter's case, the second test resulted in only 5 leaks out of 722 components. If a test the next month gave the same results, the nonleaking valves, which are likely to be most of the 717 nonleaking sources, would then be monitored quarterly. The plant would also be a likely candidate for the "allowable percentage of valves leaking" alternative provided in Section 60.633-1 of the proposed standards. After the initial performance test, the facility could elect to use annual performance tests to demonstrate that less than 2 percent of all valves were leaking. Otherwise, the plant could use the skip-period monitoring program, as specified in Section 60.633-2, to reduce the monitoring frequency for valves to semiannually or annually. The standards provide enough flexibility to increase cost effectiveness and avoid the unnecessary monitoring of nonleakers.

The commenter indicated that the total monitoring time for 722 components using the hydrocarbon monitoring instrument was 14.4 hours. Assuming a two-man crew performed the monitoring, this equates to approximately 2.4 man-minutes per source. As shown in Table 8-3 of the BID for the proposed standards, Model Plant B has 774 components, which were estimated to require 121 labor hours per year on a quarterly basis, or 30.25 man-hours per monitoring cycle. This results in an average monitoring time of 2.34 man-minutes per component. These two values are nearly identical, so that the commenter's monitoring time supports EPA's estimated monitoring time.

6.3 EMISSION FACTORS

Comment: API (II-D-10) stated that EPA's assertion that the Rockwell compressor seal factor "probably underestimates emissions" is speculation and is untrue, according to the Rockwell research team leader.

Response: The Rockwell compressor emission factor is based on EPA and API testing of emissions into the distance piece area from only open frame compressors. The factor does not include emissions into the seal packing vent or into enclosed distance pieces. Therefore, the Rockwell emission factor is probably understated substantially. A revised emission factor, discussed in the BID for the proposed standards (Appendix G), was necessary because a review of the data used in developing the 1 kg/day emission factor showed that a large portion of the data were from residue (dry) gas compressors, which EPA intended to exempt. Therefore, the overall emission factor of 1 kg/day was not representative of the population of compressors to be regulated. The revised emission factor (6.4 kg/day) is based on a weighted average of emission factors for compressors in both wet gas and NGL service because there is a large difference in process stream VOC concentration between wet gas and NGL service compressors.

Comment: Two commenters (IV-D-13 and IV-D-19) stated that EPA had overestimated the number of centrifugal compressors in assuming that 50 percent of all compressors would be centrifugal. One commenter wrote that about 10 percent are centrifugal and 90 percent are reciprocating. Commenter IV-D-13 stated that, because of this assumption, EPA overestimated compressor VOC emissions, which are minor compared to total VOC emissions. The commenter suggested that the compressor requirements be eliminated.

Response: In all analyses of compressor controls, EPA used an average emission factor for all types of compressors, including centrifugal and reciprocating ones. Emissions are related to the compressor service (NGL and wet gas), but not to the type or operation of compressors (centrifugal and reciprocating). Therefore, the fraction of compressors assumed to be centrifugal has no bearing on the compressor emissions estimate. At proposal, EPA assumed that 50 percent of all compressors would be centrifugal only in order to determine an average cost for compressor control systems.

Comment: One commenter (IV-F-1b) stated that nonfractionating plants will not use compressors in NGL service (unless a propane refrigerant system is required to optimize plant recoveries). Therefore, the commenter stated it would be more appropriate to base compressor seal leakage on wet gas compressors only.

Response: As used in the BID for the proposed standards, as well as the proposed standards, NGL service streams are considered to be all hydrocarbon streams that contain greater than 50 weight percent VOC. Since the purpose of the natural gas plant is to extract hydrocarbons from the methane residue gas, all natural gas plants have NGL streams. Based on the content and physical characteristics of the NGL produced, the NGL stream may be moved by either pumps (for low vapor pressure products) or compressors (for high vapor pressure products). For nonfractionating plants, the NGL stream produced is typically either ethane and heavier hydrocarbons or propane and heavier hydrocarbons. Either of these mixtures would likely be high vapor pressure streams and would be transported from the process with compressors. Therefore, EPA does not necessarily agree that nonfractionating plants will not employ NGL compressors. Since an exemption for all wet gas reciprocating compressors has been added to the promulgated standards, NGL compressors represent an even larger portion of the affected compressors than assumed at proposal.

Comment: Three commenters (IV-F-1e; IV-D-31; IV-D-34) urged that compressors be exempt from the standards because of the small amount of reactive hydrocarbons emitted from compressors. Commenter IV-F-1e noted that compressors constitute less than 4 percent of the total gas plant emission inventory.

Response: Compressor seal emissions were estimated in Appendix G of the BID for the proposed standards to be 2.3 Mg/yr per seal, the highest emission factor of all VOC emission sources in natural gas plants. This average emission value was based on wet gas compressors having emissions of 0.7 Mg/yr, and NGL compressors having emissions of 5.5 Mg/yr.

As shown in Table H-1 of the BID for the proposed standards, compressors represent 17.8 percent of the emission reduction from implementing the standards for a typical new plant. Contrary to the commenter's statement that compressors represent 4 percent of the gas plant emission inventory, the Model Plant B compressor emissions (37.8 Kg/day) are 13.8 percent of the total uncontrolled Model Plant B emissions.

Comment: One commenter (IV-D-33) saw no justification for the baseline emission factors developed in Radian's July 1982 report (Docket Item II-A-23). The commenter claimed, as an example, that the VOC emission factor for valves (0.18 kg/day) was too high and should be 0.09 kg/day based on Table 1-2 of the Radian report and on the 95 percent upper bound curve. The commenter determined that leak occurrence rates of 18 percent at 100,000 ppmv (0.35 kg/day) and 82 percent at 500 ppmv (0.03 kg/day) resulted in an emission factor of 0.09 kg/day.

Response: The commenter contends that, based on the data presented in the EPA report "Frequency of Leak Occurrence and Emission Factors for Natural Gas Liquid Plants" (80-FOL-1), the average emission factor for valves should be 0.09 kg/day, rather than 0.18 kg/day used by EPA. It is true that an average leak rate calculated from the commenter's values of 500 ppmv and 100,000 ppmv would be 0.09 kg/day. However, the arithmetic average of these values does not represent a true average emission factor for all valves due to the log normal distribution of leak rates. Chapter 4 and Appendix C of the referenced document describe in detail the statistical techniques used by EPA in developing the final emission factor for valves (0.18 kg/day), which is presented in Table C-2 of the document.

6.4 MODEL PLANTS

Comment: One commenter (II-D-10, II-D-30) questioned the basis for the model plant analysis. The commenter questioned the use of components per vessel in developing model plants since different vessels have different functions and require different controls. In addition, the commenter said the use of industry-tested plants to determine the ratios of numbers of vessels is unrealistic because the API/Rockwell study did not attempt to assess emissions from typical gas plants. The Rockwell study, according to the commenter, was designed to assess emissions from typical components in gas plants; and Rockwell determined the number and variety of components after a preliminary site visit to the facilities.

Response: Since this comment was submitted in May 1981, EPA has incorporated data from test programs at two additional plants into the analysis. The model plants used in the analysis represent different levels of process complexity based on numbers of components in the process rather than on the function of the vessel. Vessels do vary in terms of function and control required, but the function or process method (e.g., refrigerated absorption, cryogenic) is not as appropriate in describing plant complexity as are numbers of components. Appendix B of the CTG for the natural gas production industry discusses the basis for the analysis, including a description of the ratio calculations and derivation of the component counts.

It should be noted that the cost and emission reductions on a per piece of equipment basis for equipment leak prevention programs, with the exception of compressor controls, is relatively independent of component count. The regulatory alternatives presented in Chapters 7 through 9 of the BID for the proposed standards were used primarily to illustrate the impacts of various available control strategies on typical plants. The standards do not correspond with any one of the available "regulatory alternatives," but are based on individually selected control techniques for each component class. For this reason, prior to proposing the standards, EPA performed a second cost analysis (Appendix H of the BID for the proposed standards) based on different control techniques for each component type rather than for model plants. This single component control cost analysis served as the basis for the standards rather than the model plants, which are used solely to estimate nationwide impacts.

6.5 NONAIR ENVIRONMENTAL IMPACTS

Comment: Two commenters (IV-F-1b and IV-D-15) disagreed with EPA's claim of a positive impact on water quality from the standards. The first commenter stated that most plant operators are required to formulate and implement spill prevention control systems and measures. He also noted that any VOC spills prevented would be likely to evaporate before causing an impact on water quality. The second commenter indicated that liquid leaks that may affect water treatment systems are not the principal focus of the proposed standards.

Response: The EPA realizes that most gas plant streams consist of high vapor pressure components that, as indicated by the commenter, will evaporate before entering drainage systems. However, some gas plants do produce light liquid products. Leaks from the sources handling light liquid products could be reasonably expected to enter plant drainage systems. Although water quality impacts are probably very minor, the impacts of the promulgated standards are positive.

The Clean Air Act directs EPA to consider the environmental impacts that result from promulgation of new source performance standards.

Section 111 states that:

> ... a standard of performance shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission energy reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

Hence, it is appropriate for EPA to have considered the water quality impacts of the standards.

7.0 COST OF CONTROL

7.1 GENERAL

Comment: One commenter (IV-D-3) claimed that all of the capital costs presented in Table 8-1 of the BID for the proposed standards are low. As an example, the commenter presented costs for compressor distance piece flare piping. The commenter argued that very few compressors in gas processing plants have only one cylinder and that most compressors have four cylinders. The commenter reasoned, therefore, that the capital cost of compressor distance piece piping ($2,451) should be increased to $9,804 per compressor. The commenter maintained that the same reasoning applies to the seal piping, gas supply system, and the rest of the cost data.

Response: The capital costs for control equipment presented in Table 8-1 of the BID for the proposed standards were all obtained from vendors or industry sources. In developing the capital costs, EPA attempted to generate cost estimates for control systems that would be representative of the "worst-case" cost situations (for example, offset mounting costs were included in the rupture disk installation cost estimate). Consequently, other commenters believed the average actual control costs should not exceed those in the BID for the proposed standards.

The commenter indicated that the capital costs for control of compressor distance piece piping would be low by a factor of four if the plant had four-cylinder compressors. The commenter is correct in realizing that, since the items included in the "distance piece piping" cost must be installed on each distance piece, a four-cylinder "compressor" would actually cost four times as much. However, the capital costs in the BID for the proposed standards are presented on an "emission source" basis, which, for the case of compressors, is each compressor seal. Since the four-cylinder compressors would have four controlled seals, the emission reductions would also be quadrupled, with no change in the control cost effectiveness.

Comment: One commenter (IV-D-3) indicated that the energy savings or recovery credits for hydrocarbons are very misleading. The commenter indicated that, according to Table 7-5 of the BID for the proposed standards, the equivalent of 750,000 barrels of oil over 5 years would would be recovered under Regulatory Alternative II. The commenter stated that this recovery would barely cover the cost of the necessary additional compression and operational costs to recover the hydrocarbons.

Response: The data presented in Table 7-5 of the BID for the proposed standards indicate the energy impacts of the NSPS. These data are not intended to illustrate the economic impacts of the energy supplies recovered, but are intended to show the impacts of the standards on the national energy reserves.

For standards requiring add-on control devices for vented process streams (such as condensers or adsorbers), energy expenditures for operation of the control equipment would be included in the analysis of the regulatory impacts. For example, a condenser system for control of a VOC vent stream, while recovering energy potential, would expend energy for operating recovery pumps, the refrigeration system, etc. For the equipment leaks NSPS, however, no additional equipment is required in order to prevent losses of hydrocarbons from valves, relief devices, pumps, or open-ended lines. The energy values "recovered" by preventing leak losses from these sources, therefore, are not offset by operational energy requirements.

EPA concurs with the commenter that the energy values saved do not completely offset the monetary cost of performing the programs required by the standards. However, the net cost effectiveness, as presented in Appendix H of the BID for the proposed standards, is reasonable.

Comment: One commenter (II-D-10) stated that in using recovery credits for demonstrating cost effectiveness, it is misleading to include quarterly or monthly monitoring results with total recovery on an annual basis. The commenter further stated that credits gained after the initial baseline screening and repair are relatively small and are only 10 percent per quarter or 5 percent per month (according to EPA estimates of percent leaks initially detected for quarterly and monthly monitoring).

Response: API submitted this comment prior to proposal and requested that it be included in the rulemaking (IV-F-1e). API contends that, since fewer leaks are found during follow-up inspections than during the initial inspections, the recovery credits should be based on the quantity of emissions reduced during a follow-up test, rather than the reductions from the initial inspection.

As explained in Section 6.1, the leak detection and repair programs required by the standards are intended to prevent leakage from occurring. The initial inspection of a facility demonstrates the emission rate from the facility in the absence of a routine leak and repair program.

A leak detection and repair program providing nearly 100 percent control would have almost no leaks detected during follow-up inspections and, therefore, would provide an emission reduction equal to the uncontrolled emissions on a continuous basis. The EPA considers this reduction from the uncontrolled leak rates to be the proper basis for the calculation of recovery credits.

Comment: One commenter (II-D-30) remarked that "front-end costs" should not be equated with "capital costs." For example, double valving open-ended lines and initial leak repair are front-end expenses that should be considered as operating costs. The commenter added that only the VOC analyzer and the compressor piping should be defined as capital costs and that remaining costs incurred are classified as expenses. According to the commenter, expense and capital costs cannot be combined without using an amortization schedule.

Response: API submitted this comment prior to proposal and requested that it be included in the rulemaking (IV-F-1e). Although the control cost of open-ended lines and initial leak repair could be treated as operating expenses, they are treated as though they were capital costs and are amortized for the purposes of these standards, because they are one-time, start-up costs. This assumes capital would be borrowed to pay these initial costs.

Comment: One commenter (IV-D-30), stating that most new, small plants are designed to operate unattended, claimed that the costs associated with repair have been grossly underestimated in the BID for the proposed standards. Similarly, another commenter (IV-D-29) stated that the effect of the proposed standards on the small, partially-attended plants is not cost effective. The commenter quoted an annual monitoring cost of $39,191.52 compared to EPA's estimate of $970 for the direct monitoring cost for Model Plant A and indicated that EPA failed to include costs for training labor, scheduling, preparation, travel, direct management, supply personnel, reporting, recordkeeping, setting up a system of compliance, tagging, and problem-solving. The commenter said that, given that gas processing plants do not contribute significantly to air pollution, these anticipated related costs are disproportionate to the marginal benefit derived and, hence, are not cost effective.

Response: The commenters contend that, since small plants are minimally attended, the costs of the standards presented by EPA are unrealistic. The cost analyses presented in Chapter 8 of the BID for the proposed standards were based on leak detection and repair programs being performed by plant personnel. The EPA recognized, prior to proposing the standards, that small gas plants may not have adequate staffing to perform the leak detection and repair program. Therefore, based on industry supplied data, EPA performed a separate cost analysis for small, unattended plants based on leak detection and repair programs being performed by corporate office personnel. These analyses were presented in Appendix F of the BID for the proposed standards and showed that the cost effectiveness of monitoring programs deteriorated rapidly for plants smaller than 10 MMscfd. Consequently, plants with capacities of 10 MMscfd and less were exempted from routine leak detection and repair programs at proposal.

The commenters mentioned numerous administrative items not specifically included in the EPA cost analyses. In preparing cost analyses for regulatory alternatives, EPA includes a percentage add-on to all control labor costs to account for administrative costs. Although EPA added 40 percent of the direct labor cost for general and administrative costs in analyzing the cost of the standards, the Agency believes that once the program is established, administrative costs will be much lower.

7.2 COMPRESSORS

Comment: One commenter (IV-D-21) thought that the costs to control emissions from compressor seals are unreasonable, considering the small return (emissions reduction) from emission control and, therefore, recommended that compressor seal control system requirements be deleted. The commenter also argued that the costs of controlling compressors are particularly high, considering the nature of the emission sources which include several small compressors. The commenter also remarked that the burden of compliance will fall on existing as well as new gas plants since replacement of a single compressor will result in an affected facility. Existing plants with some portion of a control system, such as a flare, will require new systems since the existing equipment is not designed for VOC emission control. Thus, the marginal operating economics of these facilities makes the costs unreasonably high.

Response: The commenter contends that all compressors should be excluded from the promulgated standards because the emission reductions achieved do not justify the control cost. The selection of the requirements of the standards was based on control cost effectiveness, that is, the cost per unit mass of emission reduction. At proposal, the control cost effectiveness for compressors was based on a weighted average emission factor assuming 66 percent of all compressors are in wet gas service and 34 percent of all compressors are in natural gas liquids (NGL) service. These weighting factors were based on component inventories observed during testing at operating gas plants. Given compressor emission factors of 0.7 Mg/yr and 5.5 Mg/yr for wet gas and NGL service, respectively, a weighted average emission factor of 2.3 Mg/yr was used in analyzing the compressor control cost effectiveness (Docket Item II-B-35).

Since control costs for reciprocating compressors were higher than those for centrifugal compressors, EPA averaged the costs for the two compressor types to obtain an average compressor control cost of $6,400/yr based on one-half of all compressors requiring an add-on control device as explained in Appendix H of the BID for the proposed standards. Using these cost and emission reduction values, the cost effectiveness of compressor seal vent control systems was $460/Mg, which EPA considered reasonable.

Since proposal, as discussed in the response to the next comment, EPA decided to exempt all wet gas reciprocating compressors from the promulgated standards. As shown in Table 7-1, the control cost-effectiveness values of all other compressors are reasonable. Therefore, all compressors except wet gas reciprocating compressors are covered by the promulgated standards.

Comment: Several commenters (II-D-30; IV-D-13; IV-D-23; IV-D-26; IV-D-29; IV-D-33; IV-F-1a; IV-F-1b) indicated that EPA had underestimated the average cost of compressor seal vent control systems by assuming that 50 percent of the compressors used will be of the centrifugal type. One of these commenters (IV-D-26) provided a recent industry survey showing that out of over 3,000 compressors, centrifugal compressors are utilized in only 9.8 percent of the applications of the companies surveyed. Another commenter (IV-F-1b) stated that small plants will almost exclusively utilize reciprocating compressors for technical and economic reasons. One commenter (IV-D-33) estimated that the cost for a reciprocating compressor seal vent system would be about $28,000 (including installation, foundation, and flare support). When factored into EPA's revised cost analysis (Docket Item II-B-37 and BID Appendix G), the commenter felt his estimate will justify the exemptions for reciprocating compressors in NGL or 100 percent VOC service when no control device is present. Another commenter (IV-D-34) stated that control costs were extremely high and unjustified and recommended that all compressors be exempt from the standards.

TABLE 7-1

COST EFFECTIVENESS OF COMPRESSOR VENT CONTROL SYSTEMS FOR MODEL PLANT B*

Compressor Type	Control Device Present	Cost Effectiveness ($/Mg)
Centrifugal - Wet Gas	No	710
	Yes	280
Centrifugal - NGL	No	91
	Yes	36
Reciprocating - NGL	No	280
	Yes	200

*From the BID for the proposed standards, Appendix G, Table 1, page G-14.

These commenters recommended that compressor requirements be eliminated from the standards, since a cost analysis based on reciprocating compressors only would show the cost effectiveness of compressor controls to be marginal.

Response: In determining the costs and cost effectiveness associated with controlling VOC emissions from compressors at proposal, EPA considered the costs for eight individual compressor control configurations. Specifically, EPA calculated the costs for two types of compressors (reciprocating and centrifugal) in two different VOC services (wet gas or NGL at plants either with or without an already existing control device). The resulting compressor control configurations and the cost effectiveness for each one are presented in Appendix G, Table 1 of the BID for the proposed standards. The cost effectiveness for each configuration ranged from $36/Mg, for a centrifugal compressor in NGL service at a plant with an existing control device, to $2,200/Mg for a reciprocating compressor in wet gas service at a plant without an existing control device. The $2,200/Mg cost includes the cost of installing and operating a flare as the control device.

The cost effectiveness of controlling reciprocating compressors in wet gas service at a plant without a control device ($2,200/Mg) was judged to be unreasonably high and, therefore, these compressors were exempted from the proposed standards. The cost effectiveness of controlling this same type of compressor at a plant with an existing control device was $1,700/Mg. This cost effectiveness was considered to be borderline in terms of whether it was reasonable or unreasonably high. In making this judgment, EPA assumed that typical gas plants would employ both centrifugal and reciprocating compressors (about 50 percent centrifugal and 50 percent reciprocating). About one-third of these compressors would be used in NGL service and the other two-thirds would be used in wet gas service. Because these other compressors can be controlled at much lower costs, the average cost effectiveness for the plant to control compressor emissions would be closer to $460/Mg than it would be to $1,700/Mg. This cost effectiveness was judged to be reasonable. Thus, EPA decided not to exempt from the proposed standards reciprocating compressors in wet gas service at a plant with a control device present.

Since proposal, the commenters have indicated that many plants, especially small plants, may have significantly more reciprocating compressors than centrifugal compressors, and, in some cases, an individual plant may have only reciprocating compressors. In addition, other commenters stated that all compressors at some plants would be in wet gas service (i.e., there would be no compressors in NGL service at some plants). For plants like the examples cited by the commenters, the overall compressor control cost effectiveness would be $1,700/Mg rather than the $460/Mg assumed at proposal. The $1,700/Mg cost effectiveness was judged to be unreasonably high as an average control cost effectiveness for wet gas reciprocating compressors at plants with an existing control device. For this reason, all wet gas reciprocating compressors, including those located at a plant without a control device, are exempt from the promulgated standards.

However, reciprocating compressors used in NGL service and all centrifugal compressors in wet gas or NGL service are still required to be equipped with closed vent systems because they can be controlled at a reasonable cost effectiveness, as shown in Table 7-1.

The average cost-effectiveness values for the compressor configurations (wet gas reciprocating, wet gas centrifugal, NGL reciprocating, and NGL centrifugal) are shown in Table 3-1. The values in Table 3-1 are based on averaging the costs for each compressor configuration (average cost of compressor with a control device and cost of compressor without a control device) as presented in Appendix G, Table 1, of the BID for the proposed standards. These values show that controls are cost effective for all compressors except wet gas reciprocating compressors. The promulgated standards, therefore, exempt all reciprocating compressors in wet gas service.

7.3 PRESSURE RELIEF DEVICES

Comment: One commenter (IV-D-2) indicated that the offset-mounted pressure relief valve/rupture disk configuration shown in Figure 4-1 of the BID for the proposed standards is rarely used in industry. The commenter said that current industry practice is to mount the rupture disk directly under the relief valve except where fragmenting graphite disks are used. The commenter noted that the offset was used before the availability of nonfragmenting rupture disks and that nearly all disk manufacturers now recommend a nonfragmenting rupture disk. This mounting method is also recommended by American Petroleum Institute, American Society of Mechanical Engineers, and Insurance Service Office standards for rupture disk installation.

Response: The commenter, a rupture disk manufacturer, is concerned that rupture disks may have been considered too costly by EPA due to the assumption that offset mounting of the rupture disk and relief valve would be necessary. The commenter is correct that EPA did assume offset mounting of a rupture disk and that offset mounting would not be required in many cases. However, the capital costs shown in Table 8-1 of the BID for the proposed standards show that the additional capital cost for offset mounting is $21, which is less than 1 percent of the total average capital cost ($3,100) for new rupture disk installations. Since many rupture disks are of the fragmenting type, and offset mounting would be required, EPA included the minor cost of offset mounting in the cost estimates for pressure relief devices.

The EPA maintains the use of rupture disks as an alternative to leak detection and repair, however, as provided in Section 60.632(d) of the proposed standards. The use of rupture disks does allow for designation of pressure relief devices equipped with rupture disks as leakless equipment. In certain situations, plant operators may find rupture disks preferable to routine monitoring of relief devices. Pressure relief devices equipped with rupture disks require annual compliance testing. The compliance test for relief devices can coincide with the annual relief device safety tests normally performed by most gas plants.

Comment: One commenter (IV-D-2) requested that EPA change the language for rupture disk system costs to delete the phrase "at relatively high cost" in the preamble to the proposed standards: "installation of the rupture disk controls an additional 500 kg/yr but at the relatively high cost of $6,700/Mg" (49 FR page 2639). The commenter agreed with EPA's cost calculations for rupture disk systems, but preferred that plant owners or operators be allowed to decide what is relatively high.

Response: The phrase "at relatively high cost" relates the cost of rupture disk installations to that of routine leak detection and repair for pressure relief devices. The EPA does not intend to imply that rupture disks are overly expensive or of high cost, but merely that rupture disks have relatively high cost compared to a leak detection and repair program.

7.4 CONTROL DEVICES

Comment: Several commenters (IV-D-21, IV-D-23, IV-D-24, IV-D-29, IV-D-31, IV-D-33, IV-F-1a and b) indicated that EPA had substantially understated the cost of a suitable dedicated flare system. One commenter (IV-F-1b) indicated that a suitable flare system would cost over $60,000 (1980 dollars) compared to EPA's estimate of $11,000 shown on page G-9 of the BID for the proposed standards. Another (IV-D-23) provided a minimum cost of $100,000 to install a new flare including a smokeless flare tip, flare stack, foundation for the flare stack, and related valving and piping based on actual new smokeless flares that have been installed at his company's facilities. Other commenters (IV-D-24, IV-F-1a and IV-F-1b) stated that the cost analysis in the BID for the proposed standards does not account for the flare velocity requirements and fails to consider costs for the additional utility consumption (i.e., steam, pilot and purge gases) and ancillary control systems. One commenter (IV-D-33) could not determine from the EPA cost analysis whether the cost of the larger flare had been included.

Response: As discussed in Chapter 4, the velocity requirements for flares do not apply during malfunctions. The EPA believes that most emergency flares will have velocities below 60 ft/sec during normal operating periods. The EPA has costed other available control devices for compressors. The results of these analyses (Docket Item IV-B-7) show that flares and other control devices are cost effective when used to control emissions from wet gas and NGL centrifugal compressors, as well as NGL reciprocating compressors.

Comment: One commenter (IV-D-21) pointed out limitations in using process heaters as a VOC control device at his company. The commenter noted that, as a control device, heaters would have high operating costs (since heaters normally operate only about 50 percent of the time during the heating cycle of the regeneration process) and would not meet the design and operating standards specified in Section 60.632-9(c) of the proposed standards for efficiency, minimum residence time, or minimum temperature. In addition, since heaters usually operate at 25 to 35 psig, all vents to the heater would have to be compressed, creating greater costs and safety hazards.

Response: The EPA recognizes that, in many cases, process heaters operate on a cyclical basis and are unsuitable for use as VOC control devices. In those cases, the owner or operator would probably utilize either a flare or other control device as opposed to continuously firing the process heater (Docket Item IV-B-7). The 25 to 35 psig pressures mentioned by the commenter are typical of process heater fuel lines. However, the heater combustion chambers are normally close to atmospheric pressures, and the vent stream may be routed directly to the combustion chamber for control.

As discussed in Chapter 4, the temperature and residence time parameters for incineration are provided as acceptable design parameters to show compliance with the combustion efficiency requirement. These parameters are not required; other temperatures and/or residence times may be used.

Comment: One commenter (II-D-30) said that costs for adding double valves on open-ended lines are underestimated because these costs should include recordkeeping, vehicle use, and source identification and tagging. In addition, the commenter wrote that the cost estimate for capping open-ended lines is based on the price of a 1-inch, screw-on type globe valve and the incorrect assumption that any lines larger than 1 inch can be reduced to 1 inch. The commenter suggested that EPA review the 721 open-ended lines tested as reported in Appendix A of the CTG for equipment leaks of VOC in natural gas plants and base the costs on a distribution of line sizes.

Response: API submitted this comment prior to proposal and requested that it be included in the rulemaking (IV-F-1e). Double valving an open-ended line does not require additional recordkeeping or tagging because the second valve would not be subject to the valve leak detection and repair requirements.

Complying with the standards does not necessitate installation of a second valve. Open-ended lines may be capped or plugged at much lower costs. The basis for the cost estimate is the price of a one-inch, screw-on type globe valve, which reflects the maximum cost likely to be incurred for control of open-ended line emissions. Larger lines would likely have a blind flange installed at a similar cost, and smaller lines would be capped or plugged at a much lower cost.

7.5 LEAK DETECTION AND REPAIR

Comment: One commenter (II-D-30) stated that the costs for the labor associated with leak detection are severely underestimated, they do not apply to gas plants, and they are out of date. Monitoring time, according to the commenter, is a function of such factors as plant configuration, the monitoring method, the personnel, the weather, and the location of the component. Monitoring labor charges of $4 per source for contractor labor and $3.50 per source for plant personnel (not including leak repair, resampling after repair, or initial design, acquisition, or implementation of the monitoring network) were offered. It was also argued that front-end set-up costs, equipment depreciation, and instrument maintenance should be included, as well as cost of platform for inaccessible sources [Note: This comment was made in March 1982; therefore, the costs reflect that date].

Response: API submitted this comment prior to proposal and requested that it be included in the rulemaking (IV-F-1e). The monitoring time estimates for plant equipment are based on the results of refinery inspections and have been corroborated in chemical plant testing. Since gas plants are similar in construction, and even more compact than refineries, the monitoring time estimates are valid for gas plants. Set-up costs, equipment depreciation, and instrument maintenance costs are included in the cost analysis. Leak detection costs account for field labor time only. Administrative, support, and instrument costs to implement the standards are itemized separately. The leak detection and repair costs are based on field monitoring under all weather conditions. For Model Plant B, EPA's estimated costs fall within the range of costs the commenter quotes. With 750 valves maintained at 2 man-minutes per inspection and one-fourth the annual instrument cost of $5,500, the cost per valve inspection is $2.67. The date the estimates were made is unimportant, as a fixed-year basis is always used for making cost comparisons. A comparison of costs for leak detection and repair between industry and EPA estimates is presented in Docket Item IV-B-5.

Comment: Four commenters (IV-D-20; IV-D-21; IV-D-26; IV-D-36) stated that the cost effectiveness of monthly monitoring for valves and pumps is unreasonable and recommended that the monitoring frequency be reduced to quarterly or annual. One commenter (IV-D-20) noted that Table 1 of the preamble to the proposed standards shows that the incremental emission reductions from quarterly to monthly monitoring would be 7 percent for valves and 15 percent for pumps. The commenter believed that this increase in emission reduction does not justify a 300 percent increase in monitoring time and costs. A second commenter (IV-D-36) argued that a monthly program cannot be justified as cost effective based on the costs incurred at Conoco's Cashion plant, the significantly lower repair rate achieved, and the low leak rate which occurred at the second test. A third commenter derived cost effectiveness values of $1984/Mg (monthly), $768/Mg (quarterly), and $160/Mg (annually) from monitoring program net annual costs and emission reductions. The commenter based his cost estimates on the average bid price of several leak detection contractors, and the emission reductions (in part) for Regulatory Alternative III in Table 8-8 of the BID for the proposed standards.

A fourth commenter (IV-D-21) said that an annual leak detection and repair program for valves, relief devices, and pumps with a corresponding annual report, would reduce industry's compliance cost and still meet the goals of the Clean Air Act. The commenter thought that a monthly leak detection and repair program is excessively burdensome without much VOC emission reduction. In particular, scheduling monthly monitoring is difficult because it would depend upon the availability of outside personnel, weather problems, and unscheduled plant problems.

Response: The goal of the Clean Air Act is to apply best demonstrated technology (BDT) to newly constructed, modified, or reconstructed sources. The Act requires that standards of performance reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impacts and energy requirements. In selecting the basis of the standards for valves, EPA considered quarterly and monthly monitoring as discussed in Section 3.2. Each of these intervals was compared in terms of the emission reduction achievable and cost effectiveness of the leak detection and repair programs as presented in Appendix H of the BID for the proposed standards. Monthly monitoring was selected at proposal as the basis for the standards for valves because it achieves the largest emission reduction at reasonable costs and cost effectiveness. Based on these estimates EPA considers monthly monitoring BDT for valves.

Available data (Docket Items II-A-25 and II-A-37) indicate that leak recurrence is an important factor in predicting leaks from valves. If a valve leaks, then it is more likely to leak in the future than a valve that has not leaked. These data also show that some valves leak less frequently than others. Because leak recurrence can be important in predicting leaks, EPA considers the annual cost of monthly monitoring of valves that leak infrequently to be unreasonably high in comparison to the annual cost of quarterly monitoring, considering the emission reduction achieved by monthly and quarterly monitoring. Therefore, the proposed standards allowed quarterly monitoring for valves that have been found not to leak for 2 successive months, resulting in a monthly/quarterly implementation program. The EPA expects that most affected facilities would follow the monthly/quarterly schedule and that most valves would be on the quarterly inspection schedule. The annual emission reduction achieved by monthly/quarterly monitoring is 37.7 Mg for a Model Plant B, and the cost effectiveness is a credit of $100/Mg. The incremental cost effectiveness of monthly/quarterly from quarterly leak detection and repair is $240 per Mg (see Table 3-1). As stated above, the selection of the standards was based on emission reduction, cost effectiveness, and incremental cost effectiveness and not on the percent increase between monthly and quarterly monitoring. Additionally, the actual costs for valves under the standards is likely to be more closely represented by the costs estimated for quarterly monitoring. Consequently, the actual percent increase in cost will be far less than the 300 percent increase claimed by one commenter.

In reviewing the data submitted by the commenters (Docket Item IV-B-5), it was found that the commenters estimated total annual cost to perform the leak detection and repair requirements of the standards were generally in agreement with EPA's cost estimates. Costs projected by commenters IV-D-21 and IV-D-22 were lower than the costs estimates using the calculation method presented in the BID for the proposed standards. The projected costs presented by commenter IV-D-26 from contractor bids and the actual costs for one-time leak survey are higher than costs estimated by EPA. However, these costs are similar after correcting the GPA projections for several misconceptions in the requirements of the standards and correcting accounting errors. Table 7-2 presents a summary of the total annual cost estimates to perform a leak detection and repair program at a 500-component gas plant.

The commenter included the costs to tag each component, record and report more information than required, and other activities that would not occur at a typical plant inspection. The contractor bids were also based on 1984 dollars and did not consider that most components (i.e., valves) would be monitored on a quarterly rather than monthly basis. Some of the contractors providing bids may not have had any experience in leak detection and repair work (Docket Item IV-E-1), and could have overestimated the cost of performing the work.

Comment: One commenter (IV-F-1b) stated that EPA had failed to include several cost elements in their analyses of leak detection and repair program costs. These items included:

- The initial setup costs for special flowsheets and component identification,
- The additional costs of the "more elaborate" recordkeeping and reporting contained in the proposal, and
- The cost of lost product associated with any special shutdowns required to repair minor valve leaks.

Response: The EPA disagrees with the commenter's contention that EPA failed to include several cost elements in their analysis. The commenter's first example cites initial setup costs for special flowsheets and component identification. As discussed in Chapter 11, detailed schematics, design specifications, and piping and instrumentation diagrams are included in the recordkeeping requirements for closed vent systems and control devices as specified in Section 60.636(d)(1) of the proposed standards. However, this information should already be available to operators and, consequently, little burden would be incurred by plants as a result of the standards.

TABLE 7-2. SUMMARY OF TOTAL ANNUAL COSTS TO PERFORM LEAK DETECTION AND REPAIR PROGRAM AT A 500-COMPONENT GAS PLANT

Source of Estimate[a]	Total Annual Cost, 1980 dollars
EPA Proposal BID[b]	36,000
GPA Testing at Conoco Cashion gas plant[c]	34,800
Union Oil Company[d]	28,000
EPA-corrected value for GPA estimate	35,250

[a] Docket Item IV-B-5.

[b] Costs are based on monthly leak detection and repair for pumps, quarterly for pressure relief devices, and monthly/quarterly for valves. Inspections are performed by a two-person team (one plant person and one contractor). Based on 500 total components, the equipment distribution is proportionate to Model Plant A equipment count: 490 valves, 5 pressure relief devices, and 5 pump seals. On the average, EPA estimates about 1.1 minutes to monitor a component. Hence, about 3 hours would be required to monitor the gas plant during a typical inspection. This assumes contractor or central office will purchase two monitoring instruments and use them to inspect 5 plants.

[c] Itemized cost submitted by GPA represents second-year costs (corrected to 1980 dollars) which are based on the ratio of Chemical Engineering cost indices (263.2/319.3. First-year costs (corrected to 1980 dollars) are $37,100, which are higher than subsequent years because the cost of the first test is not amortized by GPA.

[d] Docket Item IV-D-22. Costs adjusted to 1980 dollars using cost index factor of 263.2/319.3 from Chemical Engineering. Costs submitted by Union are based on a monthly monitoring program for an average plant (35 MMcfd), 508 components tested at a rate of 2.6 man-minutes per component.

[e] Docket Item IV-B-5, Table 3. Based on Chemical Engineering cost indices (263.2/319.3) calculated from 1984 dollar values.

Component identification is also required under the recordkeeping requirements. Section 60.636(b) of the proposed standards clearly states, however, that an identification number is to be attached to leaking equipment and is not required for all equipment. This requirement has not changed since proposal. Identification can be accomplished by monitoring teams affixing inexpensive tags to leaking components. The cost for tags for leaking components is very small.

The commenter's reference to "more elaborate" recordkeeping and reporting contained in the proposal may be interpreted as EPA's failure to attach a cost to gathering each individual piece of information that must be recorded or reported. In this case, EPA has responded to similar comments in Chapter 11, Recordkeeping and Reporting. However, the commenter may also be referring to very elaborate recordkeeping and reporting practices presently implemented in the petroleum refining industry. The commenter would be correct by inferring that facilities may implement more elaborate information systems than required under the standards. Several refineries collect far more information than required by existing State and local regulations because their experience has demonstrated the usefulness of the information. Added benefits include minimizing product loss, information to make better future purchases of equipment by manufacturer and type, and developing more efficient maintenance practices.

Furthermore, EPA has not accounted for lost product associated with special shutdowns because the standards do not require special shutdowns as the commenter remarked. The EPA has included provisions (Section 60.632-8 of the proposed standards) allowing the delay of repair for equipment leaks whenever repair is technically infeasible without a process unit shutdown.

Comment: One commenter (II-D-10) expressed concern that monitoring time estimates do not include time for personnel travel to the work site or for reaching the component once on site. As an example, the commenter stated that relief valves located on top of gas plant vessels might be 50 to 120 feet high, accessible by a ladder. According to the commenter, climbing up and down a 50-foot column requires more than 8 minutes.

Response: The EPA recognizes that some components will require more time to monitor than the estimates used in the cost analysis. The cost of monitoring is based on average monitoring times, measured during actual test programs. Most sources will require less than average times to monitor, so that a few sources requiring greater than average time will result in the total monitoring time being that presented in the BID for the proposed standards.

Comment: Two commenters (IV-D-11; IV-D-34) maintained that the proposed standards would be burdensome in view of the instrumentation involved in monitoring. As an example, the commenter wrote that the cost of a typical VOC analyzer is approximately $5,000, with an annual operating cost for supplies and labor of $4,000. This $9,000 first-year cost is exorbitant compared to the cost of current (audible, visual, and olfactory) leak detection practices in the commenter's opinion.

Response: The EPA based the cost for instrument monitoring on one of the available VOC analyzers at $4,600 per instrument (in 1980 dollars). This cost is similar to the $5,000 (assumed to be in 1984 dollars) presented by the commenter. Although less expensive VOC analyzers are available, EPA used the higher cost to estimate the cost impacts of the standards. In addition, the cost analysis, presented in Chapter 8 of the BID for the proposed standards, includes the cost of two instruments. The standards only require one instrument; however, a second instrument is included in the cost analysis because plant operators may need to purchase a second instrument as a spare in the event the first becomes inoperable. Alternatively, operators could simply stock spare parts for the instrument. The total estimated capital cost for instrument monitors per gas processing unit is $9,200.

Annual costs for monitoring instruments include annualized capital costs and annual operating costs. The EPA estimated annualized capital costs at $2,100 per gas processing unit. This cost is based on a 6-year life for the instruments and an annual interest rate of 10 percent. Estimated annual operating costs include $3,000 for materials and labor to maintain and calibrate the instruments and $370 for miscellaneous costs. The EPA's estimated total operating costs are $3,370 which compares closely with the commenter's estimate of $4,000 (assumed to be 1984 dollars). The EPA's total annual cost, therefore, is approximately $5,500.

Given the commenter's operating costs and annualizing the commenter's purchase price for two instruments adjusted for the cost year basis results in a lower annual cost than estimated by EPA. The Chemical Engineering cost index for June 1980 represents about 75 percent of the cost index in December 1983 dollars. Therefore, the commenter's purchase price for two instruments amounts to $7,500 in 1980 dollars, and annualized over 6 years at 10 percent interest at $1,725. The commenter's operating costs would equate to about $3,000 (assuming that the operating costs would be the same for one instrument as two). The commenter's total annualized cost would be nearly $4,700 or only 85 percent of the cost EPA used as the basis for the cost and economic impact analysis of the standards.

Actual annual instrument costs may be significantly less than EPA estimated. As mentioned, less expensive VOC analyzers are available and operators may use a soap solution to screen components as provided in Method 21. Soaping may reduce labor time during inspections and reduce wear on instruments. Operators may also find it more economical to stock spare parts than to purchase a spare instrument. Nevertheless, the purchase of a VOC analyzer is necessary to detect for leaking equipment in order to determine compliance with the 10,000 ppm leak definition or the 500 ppm no detectable emissions limit. The commenter's current practices of audible, visual, and olfactory leak detection are ineffective in discerning all equipment leaks. Also, soaping is not applicable to all equipment types (i.e., rotating or reciprocating shafts). As mentioned, the cost analyses in the BID for the proposed standards assume two instruments are purchased for each plant. Most plants would be able to share monitoring instruments with other plants within the same corporation or, where contractors are utilized, with other companies. A second possibility is for a company to purchase one instrument for each plant, and one or two spare instruments to be shared by all of its plants. Where monitoring is to be performed by central office personnel, the company would probably purchase two or three instruments to be used for all plants.

Although the instrument cost may appear high to the commenter, the majority of the costs are offset by the value of the products saved through loss prevention. For example, Model Plant B has annual recovery credits due to leak detection and repair programs of $13,230/yr with annual program gross costs of $13,944/yr (based on values for labor and recovery credits presented in Appendix H of the BID for the proposed standards). Therefore, the leak detection repair program net cost is less than $800/yr, while reducing emissions by 45.7 Mg/yr.

8.0 ECONOMIC IMPACTS

8.1 PRICES

Comment: One commenter on two occasions (IV-F-1a; IV-D-26) contended that natural gas processors will have to bear the full costs of compliance with the standards and will not be able to recover these costs. The commenter cited that natural gas processing economics is based on the margin between the value of natural gas liquids components as a fuel in natural gas compared to the value as a petrochemical feedstock or liquid fuels. The economics is not based on general energy costs as assumed in the EPA analysis. The commenter added that these margins are quite small, particularly for ethane and propane components, such that additional operating costs could make new plant construction uneconomical. The commenter went on to indicate that natural gas is sold on long-term, fixed-price contracts.

Response: The commenter raises two issues that are discussed below:

(1) the role of long-term contracts in predetermining natural gas prices, and

(2) the relevant process economics for an economic impact analysis.

1. Natural Gas Pricing

The NSPS will affect primarily new sources of natural gas, but some existing sources of natural gas are also expected to be affected. Long-term, fixed contract prices have been negotiated for some of the output of existing wells. The term of some of these contracts, from date of origin to date of termination, is as much as 25 years. However, in recent years (since the mid-1970's) a great deal of new natural gas output has been sold on the basis of prices negotiated in contracts with a much shorter term of completion (2 to 3 years). Furthermore, over the same time period, increasing amounts of natural gas have been sold on the spot market at spot, or current, market prices. In addition, many of the long-term gas contracts under which natural gas used to be marketed (which were negotiated during the 1950's and early 1960's) have been or will shortly be terminated. Thus it is reasonable to assume either that the output from natural gas wells will be marketed in the future at current prices or at prices negotiated under medium term contracts that are closely tied to expected or actual future spot prices for natural gas (or perhaps linked to a general energy price index; for example, a 6-month moving average index for oil prices).

2. Process Economics

The commenter contends that the relevant process economics for natural gas plants should involve a comparison of the profitability of natural gas liquids in its alternative end uses. The commenter identifies three general categories of end use:

- Natural gas liquids components as a fuel in natural gas
- Natural gas liquids as a petrochemical feedstock
- Natural gas liquids as a liquid fuels

If the standards were likely to have a measurable effect on the cost of natural gas as a feedstock to any of the above uses, then the relative economic impacts of the regulation on each of these indirectly affected markets would have to be estimated. However, the economic impact analysis indicates that the market price for natural gas is not likely to increase measurably as a result of the NSPS. Therefore, the process economics issues raised by the commenter concerning processes that utilize natural gas as a feedstock do not have to be taken into account in the economic analysis as the NSPS is estimated to have no significant impacts on the economic conditions under which firms involved in those markets operate.

It is possible that the commenter is concerned about the effects of the NSPS on vertically integrated firms involved in gas exploration and well head production in addition to downstream activities, such as the manufacture of petrochemicals or liquid fuels. These firms, however, have the option of selling or buying natural gas on the open market. Thus the opportunity cost to them of natural gas as a feedstock in their downstream operations is in fact the market price of that gas. Thus the process economics of and profitability of downstream activities involving natural gas will be unchanged by the NSPS for the reasons discussed above.

Comment: One commenter (IV-D-3) claimed that the assumption by EPA (page 9-12 in the BID for the proposed standards) is untrue that gas deregulation would be in effect and gas prices, along with liquid prices, will increase. The commenter maintained that if prices decrease or usage of natural gas decreases, the impact of the standards would be greater and perhaps could slow or stop growth in the industry.

Response: The EPA acknowledges that the price of natural gas in the future will likely fluctuate. In all likelihood the price will be relatively low in the 1985-1990 time frame but will then begin to slowly increase into the mid-1990's. In any case, the price of methane-ethane (Table 8-5 in the BID for the proposed standards) used to calculate recovery credits is based on a natural gas price of $1.46/Mcf. This price is very low and is, in fact, considerably lower than even the low projections for the 1985-1990 time frame.

Comment: One commenter (IV-D-12) expressed concern that the additional cost burden imposed on the gas industry by the proposed standards must be paid eventually by the consumer. The commenter added that the negative effect on the environment of switching from gas to other fuels (because of increased gas costs), which would occur mainly in populated areas, would more than offset the environmental benefit to any remote rural areas.

Response: The EPA economic analyses, prepared prior to proposing the VOC equipment leak standards, are presented in Chapter 9 of the BID for the proposed standards. These analyses, as discussed in Section 9.2 of the BID for the proposed standards are used to determine the maximum price increases required to maintain the same profitability as would be present in the absence of the standards. Page 9-30 of the BID for the proposed standards indicates that changes in natural gas prices would be less than 0.5 percent for the most stringent of the regulatory alternatives considered. Based on the ratio of the cost of the actual standards to the cost of the most stringent regulatory alternative, the standards will cause less than a 0.07 percent increase in gas prices. The actual natural gas cost increase due to the effects of the standards is expected to be less than 0.3 ¢/Mcf.

Since the price increases are very small, and the demand for natural gas is relatively inelastic, it is highly unlikely that such small increases in prices would have any effect on natural gas usage. Alternative fuels (as shown in Table 9-12 of the BID for the proposed standards are more expensive than natural gas, even if the price increases are understated. Therefore, no adverse environmental impacts from fuel switching are likely.

Comment: One commenter (IV-D-30) stated that EPA's assessment of the economic impacts of the standards based on natural gas prices was not accurate. The effect of the proposed standards on certain petrochemical feedstocks, propane for rural heating, and butane and natural gasoline for motor fuels should be considered. The commenter noted that gas plants are built because natural gas liquids are worth more in a separate liquid phase than in a vapor phase mingled with lighter natural gas components, and that this difference (the margin) is often slight and changes rapidly.

Response: The commenter contends that, since the purpose of natural gas processing plants is to produce natural gas liquids by extraction from the natural gas, the economic analysis should be based on natural gas liquids prices rather than natural gas prices. The EPA realizes that in some situations, natural gas liquids prices could be affected by the proposed standards. However, most of the impacts would be very slight due to the small compliance costs with the standards. It should also be pointed out that one of the primary goals of examining natural gas prices was the determination of product recovery credit. The recovery credits calculated are lower than actual, since they are based on a combination of natural gas and natural gas liquids prices, and natural gas prices are expected to be higher than the $1.46/Mcf used by EPA.

8.2 INDUSTRY IMPACTS

Comment: One commenter (IV-D-3) stated that the annual costs of implementing the standards would be in the neighborhood of 2 percent to 13 percent of annual revenues for two plants owned by his company, compared to less than 0.01 percent claimed by EPA in the preamble to the proposed standards. The commenter did not provide any explanation of the calculation of the relative cost values claimed.

Response: The EPA indicated in the preamble to the proposed standards a value of 0.1 percent as the maximum increase in consumer gas prices, rather than 0.01 percent as indicated by the commenter. The estimated cost to industry of less than 0.1 percent of revenues is based on industry average values and, therefore, could be higher or lower for individual plants. The EPA expects that costs could be as high as 2 percent of revenues at only a few plants; however, EPA does not think that the costs of the standards could be as high as 13 percent of revenues at any plant.

8.3 SMALL BUSINESSES

Comment: Two commenters (II-B-23; IV-D-3) stated that, contrary to EPA assertions, many gas plants would qualify as a small business based on a criterion of less than 500 employees.

Response: The EPA recognizes that, based on a criterion of less than 500 employees, some companies producing natural gas qualify as small businesses. However, the standards are based on cost-effective control techniques for significant emission sources, with the cost effectiveness based on the product values of gas plant products. In general, the standards are as cost effective for small businesses as for large businesses since the costs and emissions reductions are independent of business size.

Small nonfractionating plants (<10 MMscfd) are excluded from leak detection and repair programs due to poor cost effectiveness. This exclusion applies to small plants owned by large businesses as well as those owned by small businesses.

The Regulatory Flexibility Act states that if there are a significant number of "small gas companies" that will incur adverse economic impacts as a result of the regulation, a regulatory flexibility analysis is required. Since small businesses are not expected to incur adverse impacts, no analysis is required for these standards.

Comment: One commenter (IV-D-23) remarked that a large majority of compressors are fitted with open distance pieces and cannot be fitted with closed and sealed distance pieces. Some of the smaller compressor manufacturers do not offer the accessory equipment, such as double distance pieces. Consequently, the standards for compressors will cause the smaller compressor manufacturers to go out of business. Since only large manufacturers will be able to supply compressors to the gas industry, the standards will force a limited competition situation.

Response: The EPA recognizes that some existing compressor designs cannot be technologically or economically retrofitted with double distance pieces. Since proposal, EPA has decided to exclude all wet gas reciprocating compressors, so that the only reciprocating compressors subject to the standards are those in natural gas liquids service.

Compressors of any size may be fitted with double distance pieces since the physical size of the enclosed compartment may be small.

Alternative sealing techniques, such as doubly-vented barrier fluid packings or single compartment distance pieces with improved seals may also be used. Threfore, small compressor manufacturers are provided with sufficient leeway to adapt compressors to meet the requirements of the standards.

9.0 MODIFICATION AND RECONSTRUCTION

9.1 CAPITAL EXPENDITURE

Comment: Two commenters (IV-D-14 and IV-D-19) recommended that a definition for "capital expenditure" should be added to the standards before promulgation. The commenters suggested that "capital expenditure" be defined as 10 percent of the replacement cost of the affected facility at the time the process improvement is made. Replacement cost should be based upon the Chemical Engineering Construction Index or another suitable cost index. The comenters thought that this approach would make the modification provision in the NSPS more comprehensible and workable.

Another commenter (IV-D-35) recommended raising the fixed percentage AAGRA for natural gas plants from 4.5 percent to 10 percent. According to the commenter, this would bring the repair allowance threshold in line with onshore drilling and avoid discouraging process improvement modifications at existing gas plants. The commenter stated that the application of a tax rule which sets an arbitrary break point between an expense and capitalization requirements for these facilities is impractical and ignores real world problems. The commenter reasoned that gas plants are typically designed for declining production rates and, therefore, are not frequently expanded or added to as are other facilities, and thus the cost basis is normally low.

Response: The EPA agrees with the commenter's suggestion that capital expenditure can be based, in part, on a certain percentage of the replacement cost of the affected facility. After reviewing similar comments on other standards of performance (e.g., Equipment Leaks of VOC in SOCMI, Subpart VV, and Petroleum Refineries, Subpart GGG), EPA decided to provide an alternative for the definition of "capital expenditure" in 40 CFR 60.2 of the General Provisions. Although the implementation of the capital expenditure definition has been made more practicable, the original intent of the definition has been maintained.

The alternative uses an adjusted annual asset guideline repair allowance (AAGRA) and the replacement cost to determine capital expenditure. Details of the alternative, which is applicable to plants built prior to 1982, are discussed in the BID for the promulgated standards for equipment leaks of VOC in petroleum refineries (EPA-450/3-81-015b). A definition for capital expenditure was added to 40 CFR Part 60, Subpart VV (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry), Section 60.481 (49 FR 22607, May 30, 1984) and, therefore, is incorporated by reference into the promulgated standards for natural gas processing plants. "Capital expenditure" means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that exceeds P, the product of the facility's replacement cost, R, and an adjusted AAGRA, A, as reflected by the following equation:

$$P = R \times A$$

The replacement cost, R, means the capital needed to purchase all the depreciable components in a facility. The adjusted AAGRA, A, is a product of the age-adjusted percentage, Y, of the replacement cost, and the applicable basic AAGRA, B, as reflected by the following equation:

$$A = Y \times (B \div 100)$$

For Subpart KKK, B is equal to 4.5. The percent Y is determined from the following equation:

$$Y = 1.0 - 0.575 \log X, \text{ where}$$
$$X = 1982 - \text{the year of construction}$$
$$\text{and } X > 0.$$

The relationship between replacement and original costs was derived using inflation indexes (Docket Items II-B-50 and II-B-51).

In response to the request of the second commenter, the 4.5 percent AAGRA for natural gas processing plants is established by the Internal Revenue Service, and its application to NSPS is established by the General Provisions for NSPS. EPA recognizes that other industries use different AAGRA percentages (for example, the AAGRA for petroleum refineries is 7.0 percent). The AAGRA values are industry specific based on the type of operations performed by the industry and the expected repair expenses an industry is likely to incur. Consequently, the AAGRA would require adjustment by the IRS and not EPA.

9.2 MODIFICATION OF EXISTING SOURCES

Comment: One commenter (II-B-23) suggested that "modification" be defined and included in the preamble due to several uses of the term.

Response: The definition for modification is included in the General Provisions, 40 CFR 60.14; therefore, it does not need to be defined in each separate subpart.

Comment: One commenter (IV-D-37) suggested that the provisions for process improvements without a capital expenditure (Section 60.630(c)) be revised to "... process improvement that is accomplished without an increase of emissions shall not by itself be considered a modification." The commenter explained that this would give older facilities the incentive to modernize and reduce emissions if modernization did not trigger NSPS.

Response: The EPA stated its intent in Section 60.630(c) of the proposed standards that minor modifications would not be covered by the standards:

> Addition or replacement of equipment for the purpose of process improvement that is accomplished without capital expenditure shall not by itself be considered a modification under this subpart.

The capital expenditure criterion was included so that minor process improvements in a process unit that cause an increase in emissions would not subject an existing facility to the requirements of the standards.

It should be noted that any potential emission increase that results from changes in operation that require the addition of a few fugitive emission sources could be offset or nullified by controlling existing equipment or installing components with no fugitive emissions. Accordingly, there would be no modification in such a case even if the emissions occurred with a capital expenditure. The standards do not require that process improvements be made without a capital expenditure. They merely provide an exemption when the process improvements are made with such an expenditure.

As described in Chapter 5 of the BID for the proposed standards, Section 60.14 of the General Provisions limits the modification provisions to changes which result in an increase in emissions.

9.3 MISCELLANEOUS

Comment: One commenter (IV-D-19) wrote that it would be helpful if EPA would clarify that facilities under different ownership are separate sources. The commenter gave as an example the following situation. If company X modifies its CO_2 removal plant (sweetening unit) which is adjacent to and serving company Y's gas plant, the NSPS should not be triggered.

Response: The NSPS defines an affected facility as either an individual compressor or all equipment in a process unit. If an individual process unit (such as a dehydrator) is modified, the process unit is then subject to the requirements of the standards. However, the remainder of the plant would not become subject to the standards. In the commenter's example, the sweetening unit would become subject to the standards, but the remainder of the plant would not.

10.0 TEST METHODS

10.1 LEAK DETECTION METHODS

Comment: Numerous commenters (IV-D-35; II-B-23; II-D-20; II-D-30; II-E-8) stated that EPA should recognize the validity of less costly, faster, easier, and more accurate leak detection using soap scoring. One commenter (IV-D-35) noted that several factors lead to the conclusion that soap scoring is better than instrument monitoring:

- Cost - a small trigger-activated pump bottle ($1.75) can be used for soap scoring as opposed to a $6,000 instrument for instrument monitoring.
- Ease of testing - the soap solution bottle is much lighter (1/2 to 1 kg) than the monitoring instrument (7 to 8 kg), which is important when the operator must climb over pipes, climb ladders, or traverse walkways.
- Accuracy - the commenter noted that industry demonstrated, by statistically comparing the soap score with volumetric leak rate and concentration measurements, the absolute accuracy of the soap test (Eaton, et. al. 1980). The EPA, according to the commenter, attempted to show that the detection instrument is as accurate as the soap test (DuBose, et. al., 1982). However, EPA performed their analysis by comparing instrument readings with soap scores rather than actual leak rates. Thus, the validity of EPA's claims of accurate leak detection using the instrument is not supported by gas plant data.

In one test (Eaton, 1980), commenter IV-D-35 reported that 81 percent of all OVA-detected leaks were found to have a soap score of three or greater. Union Oil Company data (Anderson, 1984) showed identical results for the two methods, but soap scoring was almost twice as fast. Based on these reasons, the commenter suggested the proposed standards be modified to allow use of soap testing, with a soap score of three or more indicating a leak.

Another commenter (IV-D-10) also recommended that EPA allow the use of soap scoring at natural gas plants to quantify VOC leaks from components for which soap scoring is effective. The commenter wrote that, while soap scoring is subjective, the method has been shown to correlate accurately with leak rate and concentration measurements. Commenters IV-D-30 and IV-D-35 provided results of a 1982 Western Oil and Gas Association (WOGA) training session in which 500 measurements were made using 10 hexane-calibrated OVA's. The data indicated that 81 percent of all OVA-detected leaks received soap scores of 3 or greater, while 92 percent of all OVA-detected leaks received soap scores of 2 or greater. Commenter IV-D-10 felt that due to the variability of OVA readings, the correlation between OVA readings and soap scores is probably better than the data indicate.

[Note: OVA is a registered trademark, use of which does not imply endorsement by EPA.]

Response: Prior to promulgation of Method 21, an alternative soap screening procedure was added for sources that can be tested with a soap solution. These sources are restricted to ones with non-moving seals, moderate surface temperatures, without large openings to atmosphere, and without evidence of liquid leakage. The soap solution is sprayed on all applicable sources, and the potential leak sites are observed to determine if bubbles are formed. If no bubbles are formed, then no detectable emissions or leaks exist. If any bubbles are formed, then the instrument measurement techniques must be used to determine if a leak exists or no detectable emissions exist, as defined in the regulation.

The alternative soap solution procedure does not apply to pump seals, components with surface temperatures greater than the boiling point or less than the freezing point of the soap solution, components such as open-ended lines or valves, pressure relief device horns, vents with large openings to atmosphere, or any component where liquid leakage is present. The instrument technique specified in the method must be used for these components.

The alternative of establishing a soap scoring leak definition equivalent to a concentration-based leak definition is not included in the method and is not recommended for inclusion in an applicable regulation because of the difficulty of calibrating and normalizing a scoring technique based on bubble formation rates. A scoring technique would be based on estimated ranges of volumetric leak rates. These estimates depend on the bubble size and formation rate, which are subjective judgments of an observer. These subjective judgments could be calibrated or normalized only by requiring that the observers correctly identify and score a standard series of test bubbles. It has been reported that trained observers can correctly and repeatedly classify ranges of volumetric leak rates. However, because soap scoring requires subjective observations and since an objective concentration measurement procedure is available, a soap scoring equivalent leak definition is not recommended for this standard. The alternative procedure that has been included will allow more rapid identification of potential leaks for more rigorous concentration measurement using a monitoring instrument.

Comment: One commenter (II-D-30) listed limitations of the portable hydrocarbon detector in pointing out that the instrument is not the best survey method, as EPA claims:

- Extreme delicacy of the instrument;
- Sensitivity to correct calibration;
- Weight and inconvenience of the instrument;
- Poor repeatability;
- Lack of demonstrated accuracy;
- Time delay in achieving a reading; and
- Difficulty in receiving timely repairs of the instrument.

Response: The EPA recognizes that portable hydrocarbon detectors have limitations; however, none of the limitations prevent the use of instrument monitoring from being the recommended method of leak detection. Although typical monitoring instruments can be damaged by accidental dropping or misuse, they are not considered "extremely delicate." These instruments have been in routine use in refineries subject to State or local leak detection and repair requirements with few problems.

The absolute accuracy of the instruments is not a real concern. Since the purpose of the instrument monitoring is to locate failures of seal mechanisms, the readings observed by the instrument operator are normally much lower or much higher than the 10,000 ppm leak definition. Consequently, a minor change in the calibration of the instrument makes little difference in the number of leaks detected.

The response time of the hydrocarbon detector is required by Method 21 to be less than 30 seconds. However, 3 to 10 seconds is more representative of currently available instruments. The EPA recognizes that the instruments may be cumbersome in certain situations. However, as mentioned before, use of the instruments has been demonstrated through routine use in regulated refineries. Additionally, since this comment was written, EPA has added soap screening procedures to Method 21. The use of soap screening will allow the operator to minimize the use of the instrument, since instrument monitoring is only required for sources producing visible bubbles during soap screening. Limited use of the instrument can result in extending the instrument life as well as minimizing operator fatigue.

The instrument can be repaired by either the manufacturer or qualified repair services. Most instruments are relatively simple in design; therefore, most problems can be repaired in the field by the operator. The EPA expects the plants to maintain spare parts as recommended by the instrument manufacturer. Costs for a second (backup) instrument are included in the cost analyses of the BID for the proposed standards.

Comment: One commen[illegible] (IV-D-20) mentioned that hydrocarbons are measured using the Flame Ionization Detector (FID) principle. Such analyzers are not capable of distinguishing methane and ethane from heavier hydrocarbons. Thus, there is no way to determine the actual level of regulated hydrocarbons in either the background air or from a leak. Consequently, the commenter stated that industry and EPA will have a difficult time complying with and enforcing the proposed standards.

One commenter (IV-D-25) requested that EPA revise the definition of VOC in Section 60.2 of the General Provisions to exclude specifically methane and ethane. The commenter reasoned that Reference Method 21 detects any organic compound including methane and ethane. In fact, methane is used as a calibration gas in Reference Method 21.

Response: In selecting the affected facilities as only equipment in VOC service or wet gas service, the program limits testing of equipment to those sources with the potential to emit VOC, that is,

Reproduced from
best available copy.

those components in wet gas service or ones containing at least 10 weight percent VOC as determined by ASTM Methods E-260, E-168, or E-169. The purpose of Method 21 is, therefore, to detect whether a regulated component is leaking, and not to quantify either the leak rates or the composition of the leaking material. Therefore, there is no reason to require VOC leaks to be distinguished from methane/ethane leaks, as any component found leaking will be leaking VOC.

The 10,000 ppm leak definition represents methane/ethane and VOC combined. The leak rates presented throughout the BID for the proposed standards are based on measurements of total hydrocarbon concentrations to determine leaking/nonleaking status. As such, the testing requirements for the standards are also based on total hydrocarbon concentrations.

10.2 LEAK DEFINITION

Comment: One commenter (II-D-10) stated that there is no justification for selecting 10,000 ppm as the action level.

Response: API submitted this comment prior to proposal and requested that it be included in the rulemaking (IV-F-1e). The selection of the action level, or "leak definition," for the definition of a leak was based on several factors, which are discussed in Section 4.2.3.1 of the BID and in the preamble to the proposed standards. The rationale for the selection of the action level for valves is different from the rationale for pumps because of differences in the cause of leakage.

The best leak definition would be the one that achieved the most emission reduction at reasonable costs. Within practical limits, the emission reduction achieved would increase as the leak definition decreased, due to the increasing number of components that would be found leaking and, therefore, repaired. At a leak definition of 10,000 ppm, approximately 90 percent of all VOC leaks from valves would be detected. It is well documented that valves that have been found leaking at levels of 10,000 ppm or greater can be brought to levels below 10,000 ppm with proper maintenance. Also, as a practical matter, most commonly available hydrocarbon detectors that are considered intrinsically safe have a maximum reading of 10,000 ppm. Leak definitions higher than 10,000 ppm could, nevertheless, be selected (and dilution probes could be used with portable detectors); however, there would be less emission reduction than with the 10,000 ppm definition and no substantial associated cost savings. Consequently, there is no basis for selecting a leak definition greater than 10,000 ppm. A leak definition lower than 10,000 ppm may be practicable in the sense that leaks can be repaired to levels less than 10,000 ppm. However, EPA is unable to conclude that a leak definition lower than 10,000 ppm would provide additional emission reductions and, therefore, would be reasonable. Because the 10,000 ppm leak definition would address approximately 90 percent of the VOC leaks from valves at reasonable costs and at reasonable cost effectiveness, and because safe, available hydrocarbon detectors can read 10,000 ppm, the 10,000 ppm level was selected as the leak definition for valves. In contrast to valves, which generally have zero leakage, most pump seals leak to a certain extent while operating normally. These seals would tend to have low instrument meter readings. With time, however, as the seal begins to wear, the concentration and emission rate are likely to increase. At any time, catastrophic seal failure can occur with a large increase in the instrument meter reading and emission rate. As shown in Table 4-2 of the BID for the proposed standards, over 80 percent of the emissions from pump seals are from sources with instrument meter readings greater than or equal to 10,000 ppm. Properly designed, installed, and operated seals should have low instrument meter readings. Furthermore, the bulk of the pump seal emissions are from seals that have worn out or failed so that they have a concentration equal to or greater than 10,000 ppm. Therefore, 10,000 ppm was chosen as a reasonable action level.

It should be noted that the purpose of instrument monitoring is to detect seal failures (leaks), and not to quantify the leak rate. Although any leak definition could be selected, EPA for the reasons given believes 10,000 ppm is the appropriate level of hydrocarbon concentration to distinguish between leaking and nonleaking sources.

Comment: Two commenters remarked about the safety of testing flares. One commenter (IV-D-35) recommended deleting the requirement for compliance testing of flares using Methods 2, 2A, or 2C. The commenter stated that Methods 2, 2A or 2C expose personnel to risk of death if, during the test, a component attached to the flare relieves. The commenter claimed that requiring this test is likely to bring a challenge from the Occupational Safety and Health Administration. The second commenter (IV-D-31) added that since flares are designed to handle intermittent releases from relief valves, it is uncertain how representative velocity and gas stream Btu content determination could be made and how such measurements could be performed without endangering the safety of the testing personnel.

Response: Testing of flares should not require any measurements to be made at the flare, other than monitoring for the presence of a flame with a permanently mounted thermocouple. The velocity measurements and no substantial associated cost savings. Consequently, there is no made in Method 2 or its alternates can be made in the flare header at a distance from the flare. Therefore, no climbing or exposure to the flare is necessary. Since Method 22 requires only that the flare be observed from a distance to determine if visible emissions are occurring, no exposure to the flare is required. The standards require that flares be operated within specific velocity guidelines. The stream Btu content can be based on engineering calculations of vessel or equipment contents.

11.0 RECORDKEEPING AND REPORTING

11.1 GENERAL

Comment: Several commenters (IV-D-3, IV-D-5, IV-D-19, IV-D-20, IV-D-21, IV-D-22, IV-D-25, IV-D-26, IV-D-29, IV-D-30, IV-D-34, IV-D-36, IV-F-1a) urged EPA to reconsider the proposed recordkeeping and reporting requirements. Some of these commenters (IV-D-5; IV-D-21; IV-F-1a) expressed concern that the proposed standards included more extensive recordkeeping and reporting requirements than the previous (NAPCTAC) draft. One commenter (IV-D-25) thought the requirements should be eliminated because they are far too complicated for the small emission reductions that will result from a leak detection and repair program. Another commenter (IV-D-30) said that the recordkeeping and reporting requirements are totally counterproductive to the Federal government goals of reducing paperwork. Other commenters thought the requirements were excessive. Some commenters (IV-D-3, IV-D-34, and IV-F-1a) indicated that it will be unusually burdensome for the small plant operator to comply with these requirements because of minimal staffing. One (IV-D-3) argued that small plants would need to hire additional employees just to comply with the recordkeeping, and these additional employees could make the difference between operating and shutting down. Another commenter (IV-F-1a) did not think that EPA considered increased costs for recordkeeping, reporting, and allowances for setting up a system to comply adequately with these requirements.

Several of the commenters took exception to the semiannual reports and thought that annual reports would be sufficient. The commenters questioned the ability of EPA to review and analyze the data submitted over the next several years and noted that annual reports would be consistent with State and other Federal regulations.

Response: The commenters are incorrect in stating that recordkeeping requirements of the proposed standards are more extensive than the recordkeeping requirements of the NAPCTAC draft.

In both NAPCTAC draft and proposal standards, EPA selected the same recordkeeping requirements that would provide the necessary records for managing implementation of the required programs while ensuring effective implementation and maintenance of the proposed standards. The commenters are correct in stating that reporting requirements at proposal are more extensive than the reporting requirements at NAPCTAC. After evaluating three alternatives, EPA selected the first alternative as the reporting requirement at NAPCTAC, which provided no routine reporting of compliance other than the requirements of the General Provisions of Subpart A of 40 CFR Part 60 (notifications of construction, anticipated startup and actual startup), the requirements for notification of intention to comply with one of the alternative standards for valves, and the reports necessary for determination of equivalence of alternative means of emission limitations. Compliance under this alternative would be assessed through in-plant inspections.

Since NAPCTAC, however, EPA re-evaluated the alternatives for reporting requirements of the proposed standards. The reporting requirements under the first alternative (no routine reporting) would not provide a mechanism for checking the thoroughness of the industry's efforts to reduce equipment leaks of VOC. Facilities not complying with the standards would not be using BDT as required by the Clean Air Act. The EPA believes that reporting is necessary for the effective enforcement of the standards. Reporting will reduce the necessity for many in-plant inspections, while improving the enforceability of the standards. The EPA's conclusion that reports are useful is also based on the experience of State and local air quality control boards. The EPA concluded, therefore, that reporting is necessary to assess implementation of the work practice and equipment requirements of the standards without requiring excessive resources from industry and enforcement personnel and proposed that certain information be reported (i.e., submittal of semiannual reports to summarize information on leaking equipment and the number of leaks detected and repaired).

One of the commenters asserted that EPA did not consider increased costs for recordkeeping and reporting and for setting up a system for compliance with these requirements. On the contrary, these costs are included in the cost analysis of the standards as administrative costs. In addition, contrary to the commenter's remarks, EPA did make allowances for the costs of setting up a system to ensure compliance with these requirements. The EPA is required under the Paperwork Reduction Act of 1980 (PL-511) to submit a request to the Office of Management and Budget (OMB) for approval of recordkeeping and reporting requirements that qualify as an "information collection request" (ICR). For the purposes of OMB's review, an analysis was presented of the need for information, methods of ensuring the quality of data obtained, alternatives to the information collection, and estimated burden hours and cost to the industry and to EPA of complying with the requirements. The costs of recordkeeping and reporting for both industry and EPA at proposal are presented in Docket Item II-F-3. Since proposal, EPA costs of reviewing reports and compliance inspections have been revised because of errors made in the estimates at proposal and because of revisions in ICR collection procedures as discussed in the next response to comment. The revised costs are presented in Docket Item IV-H-2.

The commenters also expressed concern that the recordkeeping and reporting requirements would be burdensome for small plant operators and that additional employees would need to be hired just to comply with the recordkeeping requirements. The EPA considered the staffing needs of plants in implementing the standards and analyzed the impacts of the standards on small plants. The EPA recognizes that some small plants operate without technically trained personnel because of the type of process that is performed there. In particular, small nonfractionating plants often operate either unmanned or without a staff having the technical ability to conduct a leak detection and repair program and to maintain the associated records and reports. In these cases, EPA analyzed the additional cost of hiring an outside consultant or using central office personnel that would be needed and judged the costs to be unreasonable at nonfractionating plants having capacities below 10 million standard cubic feet per day (MMscfd). The EPA decided, therefore, to exempt any nonfractionating plant whose capacity is 10 million scfd or less of field gas from the routine monitoring requirements (and the associated recordkeeping and reporting requirements) for valves, pumps, and pressure relief devices. All fractionating plants, however, regardless of capacity are required to implement the routine monitoring requirements because these plants require the presence of technically trained personnel. The recordkeeping and reporting requirements have little impact on the cost of the standards; therefore, EPA does not anticipate any disruption in plant operations or closings attributable to these requirements. These requirements are considered the minimum consistent with adequate enforcement; therefore, the burden on owners and operators is the minimum necessary to enforce the standards adequately.

Comment: One commenter stated that the reporting and recordkeeping requirements of 0.15 person-years per plant given in the preamble to the proposed standards (p. 2648-2) are low. The commenter offered what he considered more realistic impacts than the EPA estimates. The commenter estimated that the initial monitoring, recordkeeping, and reporting for a typical cryogenic plant will require 0.5 person-years. The commenter also offered that a plant representative of the 90 MMscfd/day gas plant referenced in the regulations includes over 1,000 valves, 5 pumps, and 4 compressors. The commenter also disagreed with the nationwide recordkeeping and reporting burden estimate given on page 2648 of the preamble to the proposed standards. The commenter noted that the recordkeeping and reporting impact of 6.6 person-years reported in the preamble is based on the number of plants (44) per year affected in the first 2-year period. The commenter argued that the impacts are cumulative and would, therefore, affect 220 plants in 1987. The commenter also used his 0.5 person-years per plant impact to estimate the nationwide annual burden at 22 person-years; the first 5-year average at 55 person-years, and that at the end of 5 years, the annual burden would be 110 person-years.

Response: The 0.15 person-years per plant estimate shown in the preamble to the proposed standards represents 312 labor hours/year for recordkeeping and reporting, or 26 hours per monthly monitoring period. Since most required records are generated during the actual monitoring period by the monitoring team, little additional recordkeeping and reporting effort is required. The amount of labor (26 hours) costed in the preamble for the proposed standards should be more than adequate for the average plant.

As discussed above, EPA is required to submit recordkeeping and reporting burden estimates to OMB for approval. At proposal, these estimates were required to be performed for the first 2 years of the regulations. The commenter is correct in recognizing that the fifth-year impacts would be greater, but the total burden for 220 plants would be 33 person-years, based on 0.15 person-years per plants.

It should be noted that, since proposal, OMB has revised the information collection reporting period from 2 to 3 years, so that EPA is required to submit recordkeeping and reporting burden estimates calculated over the first 3 years of the regulation. This change, however, does not affect the industry burden estimates presented at proposal because they were calculated on an annual basis.

11.2 REPORTING

Comment: Two commenters (IV-D-22 and IV-D-26) suggested eliminating the following information from the reporting requirements:

1. Instrument Identification Number - EPA would need to verify each daily calibration of the instrument for absolute control over instrument use,
2. Operator Identification Number - it should be sufficient for the operator to sign a log or report often-taken readings,
3. Date each repair was attempted if unsuccessful - only if the leak was not repairable within the 15 days allowed should any notation be made,
4. Repair method - the information EPA derives from this will not justify the burden on industry, and
5. Expected date of repair - in small plants and many large ones, there are no scheduled shutdowns or the date is unknown.

Similarly, another commenter (IV-D-23) held that the information reported should be kept as simple as possible to be useful. The commenter provided an example of information a report should contain:

1. The number and size of valves, including relief valves, found leaking, the number repaired and the number of valves that were unable to be repaired without shutting down the plant.
2. The number of leaks found in affected equipment, the number of valves that were unable to be repaired without shutting down the plant.

The commenters also thought only leaking components should be reported. One commenter (IV-D-19) thought that this information could be maintained at the plant and made available for inspection on request as is done in many other federal and State regulations. Another commenter (IV-D-20) stated that it was unnecessary to report immediately repaired components because such information does not affect the emission reductions obtained by the inspections. In addition, exemption of the reporting requirement would reduce the compliance burden on industry. One commenter (IV-D-22) added that the reporting requirements should be kept to a minimum because they reduce morale by taking time away from more productive pursuits, and that the greater the volume of detail required, the lower the quality of the information.

Response: All of these commenters contend that EPA requires excess information to be included in the required reports. In selecting the reporting requirements, EPA carefully considered what information would be required to assess adequately a plant's compliance with the standards. The resulting requirements, as proposed, represent the minimum acceptable reports.

For example, the instrument number is necessary to show that the calibrations reported are done on the same instrument used for monitoring. The number may be assigned by the plant, as instrument 1, 2, 3, etc. or may be an actual serial number. Similarly, the operator identification

It should be noted that, since proposal, OMB has revised the will serve to indicate if one operator detects consistently fewer (or consistently more) leaks than other operators. The dates of unsuccessful repair show that repair was indeed attempted and, combined with the repair method, assist both the owner or operator and EPA in determining which repair techniques are the most successful. The expected date of repair assists the appropriate enforcement agency in assessing the environmental impact of the standards by quantifying the long-term emissions that cannot be prevented.

The EPA concurs with one commenter that the required reports alone do not increase the emission reduction of the standards. However, they indicate to EPA the diligence of the plant owner or operator in complying with the standards and thus help EPA judge the necessary frequency of inspections. The EPA also concurs with keeping the reports as simple as possible and has made every effort to do so. Therefore, elaborate reports with extraneous information are neither required nor desired.

11.3 RECORDKEEPING

Comment: Several commenters offered specific examples to be deleted from the recordkeeping requirements. One commenter (IV-D-15) suggested deleting details such as schematics and design specifications for flare and alarm sensors. The commenter suggested that an annual certification of compliance by the operator would be sufficient.

The commenter wrote that since plant design criteria are generally available through State agencies, EPA, and at each gas plant, there is no need to include such information in a log.

The commenter also thought that devices found leaking that are repaired by immediate action (such as tightening of packing) should be exempt from the recordkeeping requirements of the standards. The commenter claimed that such an exemption would not affect the emission reductions obtained by the inspections and would reduce the compliance burden on industry.

Response: The details of the recordkeeping and reporting requirements were discussed in the response to the previous comment.

The commenter questions the necessity of maintaining schematics and design specifications for control devices and closed vent systems required by Section 60.636(d) of the proposed standards. The VOC control effectiveness for compressors, relief devices, pumps, or other equipment that may be controlled with a closed vent system in lieu of routine leak detection and repair is dependent on the integrity of the vent system and control device. The vent system and control device must be designed and operated properly for the emission reduction of

11.2 REPORTING

Comment: Two commenters (IV-D-22 and IV-D-26) suggested eliminating the following information from the reporting requirements:

1. Instrument Identification Number - EPA would need to verify each daily calibration of the instrument for absolute control over instrument use,
2. Operator Identification Number - it should be sufficient for the operator to sign a log or report often-taken readings,
3. Date each repair was attempted if unsuccessful - only if the leak was not repairable within the 15 days allowed should any notation be made,
4. Repair method - the information EPA derives from this will not justify the burden on industry, and
5. Expected date of repair - in small plants and many large ones, there are no scheduled shutdowns or the date is unknown.

Similarly, another commenter (IV-D-23) held that the information reported should be kept as simple as possible to be useful. The commenter provided an example of information a report should contain:

1. The number and size of valves, including relief valves, found leaking, the number repaired and the number of valves that were unable to be repaired without shutting down the plant.
2. The number of leaks found in affected equipment, the number of valves that were unable to be repaired without shutting down the plant.

The commenters also thought only leaking components should be reported. One commenter (IV-D-19) thought that this information could be maintained at the plant and made available for inspection on request as is done in many other federal and State regulations. Another commenter (IV-D-20) stated that it was unnecessary to report immediately repaired components because such information does not affect the emission reductions obtained by the inspections. In addition, exemption of the reporting requirement would reduce the compliance burden on industry. One commenter (IV-D-22) added that the reporting requirements should be kept to a minimum because they reduce morale by taking time away from more productive pursuits, and that the greater the volume of detail required, the lower the quality of the information.

Response: All of these commenters contend that EPA requires excess information to be included in the required reports. In selecting the reporting requirements, EPA carefully considered what information would be required to assess adequately a plant's compliance with the standards. The resulting requirements, as proposed, represent the minimum acceptable reports.

12.0 MISCELLANEOUS

Several comments were received that were not related to the other topic areas presented in the previous sections. These comments are discussed in this section. They include comments on determination of equivalent means of emission limitation, determination of "major rule," technology transfer, plant construction, energy requirements, effects of other regulations, extension of the public comment period, and request for reproposal of the standards.

Comment: One commenter (IV-D-29) claimed that the procedures for determining equivalent means of emission limitations are impractical for gas processing plants. Approval of equivalence would take a year when many gas plants need to be designed and constructed within 2 to 6 months. Blanket generic equivalency approvals, according to the commenter, should be allowed since gas plants are relatively small, primarily rural sources.

Responses: The EPA has provided all of the known blanket generic approvals of adequately demonstrated control techniques. Plant owners or operators may apply to EPA any time for other alternatives to either the equipment or work practice standards. Where "general use" alternatives are approved, a blanket approval has been provided. Other requests must be reviewed, evaluated, and processed according to the procedures required by the Clean Air Act.

Comment: One commenter (II-B-23) remarked that the guides in the regulation for demonstrating equivalence of work practices are unclear as to how they would be implemented.

Response: Section 60.634 of the proposed standards has been revised to simplify the wording of the equivalency determination. The term "equivalent" has been changed to "alternative" even though the primary consideration is that a plant owner or operator must still show that the alternative can achieve a reduction in VOC emissions that is at least equivalent to the VOC emission reduction achieved by the standard specified in the regulation. For example, if an owner or operator wishes to implement an alternative program for reducing valve leaks, he must collect, verify, and submit sufficient data (e.g., at least 12 months of monitoring data) to show that the alternative technique(s) used to control valve leaks achieves the same or better emission reduction than the required leak detection and repair program. The data and a written commitment by the owner or operator to implement the alternative to achieve equivalence (or better) would be submitted as an application to the Administrator for his consideration. If the Administrator determines that the alternative is at least equivalent to the required standards, then a notice to announce the opportunity for a public hearing would be published in the Federal Register. After an opportunity for a public hearing, the Administrator would publish in the Federal Register a notice permitting the use of the alternative for the purpose of compliance with the standards.

Comment: One commenter (IV-D-35) recommended changing the language of Section 60.632-1(c)(2). The proposed section reads: "If the administrator ...owner or operator shall comply with the requirements of....", which, according to the commenter, forced compliance by the owner or operator with the equivalent means of emission reduction. Since the owner or operator may wish to comply with the standards as written, the commenter suggested changing the wording of Section 60.632-1(c)(2) to read "owner or operator may substitute the requirements of that determination."

Response: The owner or operator may always elect to comply with the standards as written. Proposed Section 60.632-1(c)(2) has been replaced by Section 60.634.

Comment: One commenter (IV-D-20) stated that he believed that it was inappropriate for EPA to determine that the proposed standards are not a major rule.

Response: The proposed standards are not a major rule because they do not meet the criteria outlined in Executive Order 12291 for a major rule. In the Order a major rule is any regulation that is likely to result in:

(1) An annual effect on the economy of $100 million or more;

(2) A major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; or

(3) Significant adverse effects on competition, employment, investment, productivity, innovation, or on the ability of the United States-based enterprises to compete with foreign-based enterprises in domestic or export markets.

As stated in Section 1.3 of this document, the industrywide net annual cost for all new, modified, and reconstructed facilities will be approximately $1.6 million in 1987. This will not result in a major increase in costs or prices and will not create a significant adverse effect on competition, employment, investment, productivity, innovation or foreign competition. These costs represent a small impact on the industry and are not expected to deter construction of gas processing plants.

Comment: One commenter (IV-F-3) stated that a monthly leak detection and repair program does not constitute a "demonstrated technology" since he was unable to find any industry or local regulation that has been effectively implemented at such a frequent interval. Another commenter (II-B-23) requested that "best demonstrated" be clearly defined in order to state the intent of the proposed regulations.

Response: A "demonstrated technology" is one which is effective in reducing emissions to the atmosphere. Essex Chemical Corp. v. Ruckelshaus 486 F. 2d 427 (D.C. Cir. 1973); Portland Cement Ass'n v. Ruckelshaus 486 F. 2d 375 (D.C. Cir. 1973). Control technology can be considered "best demonstrated" technology (BDT) if it can be shown to be the best system demonstrated for the category of sources, not necessarily on the category of sources. The EPA's interpretation of demonstrated technology means that a technique used in an entirely different industry using a different process from the one being regulated can be BDT if its performance would not be affected by the differences in the sources.

Leak detection and repair programs are currently implemented in over 100 petroleum refineries throughout the country. These programs have been demonstrated by industry as a workable, effective technology to reduce VOC equipment leaks from refineries. The EPA and refinery personnel have shown that substantial emission reductions are possible through on-line repair for all valves. These programs are basically a reflection of the refinery control technique guideline document issued by EPA in 1978 (EPA-450/2-78-036, OAQPS No. 1.2-111). State and Regional air pollution control agencies have followed those guidelines to issue regulations to achieve and maintain the National Ambient Air Quality Standards for ozone.

The EPA recognizes that there are differences between refineries and gas plants; however, these differences do not preclude the transfer of control technology to the gas processing industry. In API testing of the natural gas processing industry, the process type, operating temperature and pressure, and line size were determined to be unrelated to the frequency and magnitude of equipment leaks.

The frequency of the leak detection and repair programs followed by existing programs varies. Most State Implementation Plans require quarterly inspections of gas service valves and annual inspections of light liquid service valves, whereas the Air Quality Management Districts in California require less frequent (annual) valve inspections, while requiring more stringent follow-up inspections on leaking valves. The frequency of leak detection and repair required in the standards is considered reasonable as discussed in other responses to comments and is based on valve leak occurrence, leak recurrence, costs, and emission reductions.

Comment: One commenter (IV-D-20) stated that increased emphasis will be placed on extended gas gathering systems in the future, resulting in the construction of fewer plants than estimated by EPA. Extending gas gathering systems would maintain the throughput at existing plants and would be done in preference to building new plants due to economic pressures, according to the commenter.

Response: While it is true that some companies may elect to extend gas gathering systems to continue operation of existing plants, many new plants will be constructed. A recent article in the Oil and Gas Journal states that 21 new U.S. plants were built in 1983, with 20 being built in 1984. Since new plants are often more energy efficient than older plants, and older plants may be located too far from new fields, EPA expects the industry to continue to replace older plants with new plants. Alternately, older plants may be revamped with new processes or new equipment and become subject to the NSPS requirements through modification and reconstruction provisions.

Comment: One commenter (II-B-23) disagreed with EPA's claims that the proposed standards do not require energy. The commenter stated that energy is required for maintaining pressure on compressor barrier seals, maintaining vacuum on the closed-vent systems, maintaining a pilot flare, transportation of monitoring equipment by employees, and additional use of office equipment for increased administrative duties.

Response: API submitted this comment prior to proposal and requested that it be included in the rulemaking (IV-F-1e). Although the proposed standards state that, in general, the required controls do not require energy, EPA acknowledges that energy is also required for standards requiring add-on control devices for vented process streams in addition to some of the examples cited by the commenter. However, the increase in energy for these requirements will be minimal. Furthermore, the effect of the final standards will be to maximize natural gas production for a given amount of raw material (wet gas), resulting in a net energy savings. Therefore, the standards potentially save energy rather than expend energy.

Comment: One commenter (IV-D-12) stated that certain provisions of the proposed standards are in direct conflict with the requirements of other Federal agencies with jurisdiction over his facilities. The commenter indicated that enclosure of compressor distance pieces creates an explosion hazard and is a violation of Department of Transportation rules. The commenter claimed that, since his plant was located on U.S. Bureau of Land Management property, use of a flare is specifically prohibited.

Response: The EPA knows of no requirements in the standards that are in conflict with other Federal standards. The Department of Transportation regulations apply to pipeline transmission of natural gas and other petroleum products and do not specify requirements for in-plant compressors. The Bureau of Land Management does regulate flares burning in some wilderness areas, but flares represent only one control device option available to the plant owner or operator.

Comment: Nine commenters (IV-D-1, IV-D-4, IV-D-5, IV-D-6, IV-D-7, IV-D-8, IV-D-9, IV-F-2, IV-F-3) requested that the comment period be extended to allow more time to review the proposed standards, to collect additional data to enable commenters to judge the impact of the proposed standards, or to submit more detailed comments.

Response: In response to the commenters' requests, EPA extended the comment period by 60 days. The extension notice was published in the Federal Register (49 FR 13392, April 4, 1984). The new deadline for comments was changed to June 6, 1984, to allow time for industry representatives to obtain additional data and cost estimates for implementing VOC leak detection and repair programs as well as for using flares to control compressor seal leakage.

Comment: One commenter (IV-D-32) requested that the regulation be reproposed if EPA finds the standards to be justified. According to the commenter, reproposal would afford an accommodation of changes in the proposed regulation anticipated as a result of comments.

Response: Reproposal is not necessary, since the purpose of the public comment period is to allow for changes in the proposed standards. The comments received have been considered carefully, and as a result many changes have been made to the standards as discussed in Section 1.2, "Summary of Changes Since Proposal". The need for national standards has been documented in Section 2. Because State requirements vary, the national standards are needed to prevent States with lenient air pollution requirements from attracting new industries that might deteriorate the State's air quality, as well as to prevent migration of pollutants from State to State.